David B. Raskin
202 429 6254
draskin@steptoe.com

1330 Connecticut Avenue, NW
Washington, DC 20036-1795
202 429 3000 main
www.steptoe.com

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STEPTOE & JOHNSON LLP

THIS FILING CONTAINS PROTECTED MATERIALS

February 26, 2016

Via eTariff Filing

The Honorable Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: Eversource Energy Service Company, Docket No. ER16-___-000
Northeast Utilities Service Company, Docket No. ER03-1247-000
ISO New England Inc., *et al.*, Docket Nos. RT04-2-000, ER04-116-000
Bangor Hydro-Electric Company, *et al.*, Docket No. ER04-157-000
NSTAR Electric Company, Docket No. EC06-126-000
NSTAR Electric Company, Docket No. EL07-71-000
NSTAR Electric Company, Docket No. ER07-549-000
NSTAR, *et al.* and Northeast Utilities, *et al.*, Docket No. EC11-35-000

I. INTRODUCTION

Pursuant to Section 205 of the Federal Power Act, 16 U.S.C. § 824d (2012), and Section 35.13 of the Federal Energy Regulatory Commission's ("FERC" or "Commission") regulations, 18 C.F.R. § 35.13 (2015), Eversource Energy Service Company ("Eversource Service"), on behalf of its transmission owning affiliates, NSTAR Electric Company ("NSTAR Electric"), The Connecticut Light and Power Company ("CL&P"), Public Service Company of New Hampshire ("PSNH") and Western Massachusetts Electric Company ("WMECO") (collectively the "Eversource Companies"), hereby submits for filing an application to recover the Eversource

Companies' FERC-jurisdictional transmission merger-related costs that have been incurred as the result of the April 10, 2012 merger between Northeast Utilities and NSTAR, as approved in Docket No. EC11-35-000.[1] Eversource Service demonstrates that: (1) consistent with the Merger Order, transmission merger-related costs have not been included in the transmission rates of the Eversource Companies; (2) transmission customers have realized the substantial cost savings produced by the merger; (3) the transmission merger-related savings already realized have significantly outweighed the transmission merger-related costs; and (4) under Commission policy and the Merger Order, the Eversource Companies may recover their jurisdictional transmission merger-related costs.

The merger has been very beneficial to Eversource customers, and is projected to create approximately $1 billion in enterprise-wide savings over 10 years (and $279 million specifically for transmission customers over this same time period). Moreover, in addition to meeting the Commission's requirement that transmission merger-related savings exceed transmission merger-related costs (in order to include merger-related costs in rates), the merger has provided many other more difficult to quantify benefits that go beyond this minimum requirement.

[1] *See NSTAR/ Northeast Utils.*, 136 FERC ¶ 61,016 (2011) ("Merger Order"). "Eversource" or "Eversource Energy" refers to the current merged company and all of its operating utility subsidiaries (NSTAR Electric, CL&P, PSNH, WMECO, Yankee Gas Services Company ("Yankee Gas"), and NSTAR Gas Company ("NSTAR Gas")). "Northeast Utilities" refers to the pre-merger holding company, and "NSTAR" refers to the pre-merger holding company.

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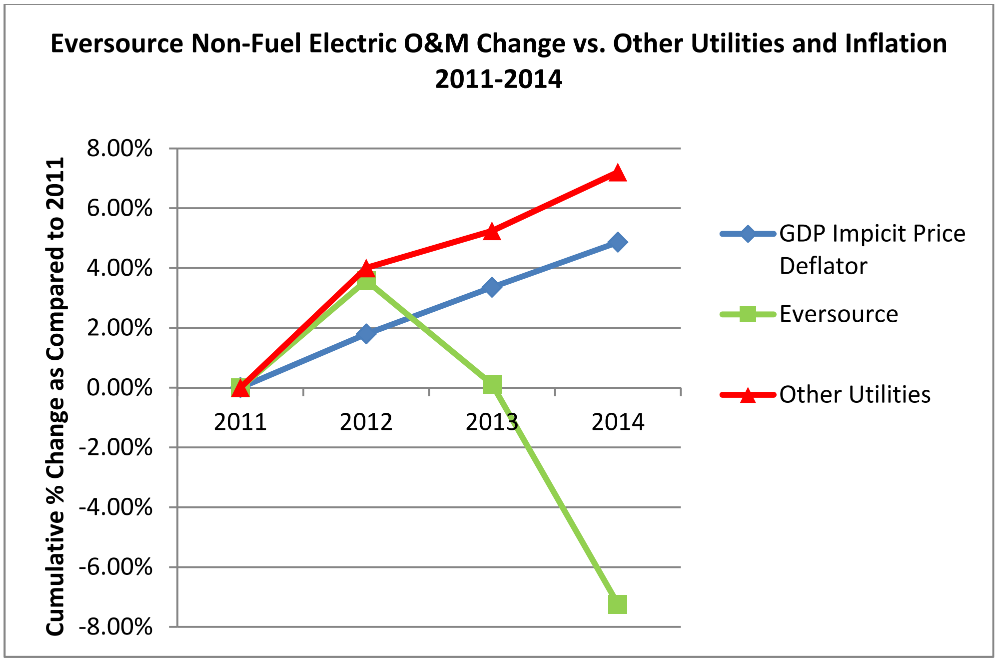
As demonstrated below, the merger's creation of a larger organization with increased efficiencies and a stronger balance sheet has achieved widespread benefits for Eversource's customers. For several years the Eversource Companies have been engaged in a substantial expansion of their transmission systems, and the larger size of the merged entity has better enabled the Eversource Companies to plan and construct these needed investments. The expanded service territory of the Eversource Companies within a single holding company system brought significant geographic diversity, enabling enhanced mutual support during storms and other service disruptions. The merged company brought together the complementary strengths of a best in class distribution company (which was largely urban in nature and had significant expertise with underground systems), with a best in class transmission provider (the service territory of which was largely suburban and rural). As a result, this synergy has enabled Eversource to decrease its Non-Fuel electric operation and maintenance expenses ("O&M")[2] by over seven percent on an enterprise-wide nominal basis between 2011 and 2014. Adjusted for inflation, this represents approximately a 12% decrease. Over the same time period, other electric utilities have faced rising Non-Fuel electric O&M costs roughly commensurate to inflation. The chart below illustrates the significance of Eversource's reduction:

[2] "Non-Fuel" electric O&M expenses are specifically defined in the testimony of Christine Vaughan. *See* Exhibit No. ES-100, Section IV.C. In general, they are electric O&M expenses, excluding certain expenses (such as the price of power that Eversource purchases) over which Eversource generally has no control and which would not be impacted by NU and NSTAR's decision to merge.



The benefits associated with the merged company's expanded size also include substantial, documented improvements in service reliability, and an improved financial condition for the Eversource Companies, which reduces the cost of borrowing. These benefits have accrued to all of Eversource's customers, including transmission customers, in the form of lower expenses than what would have been experienced absent the merger, service improvements, and an improved ability to respond to regional problems.

State regulators in Connecticut and Massachusetts have recognized the merger's substantial benefits, and have approved recovery of retail electric distribution (CT) and retail gas distribution (MA) merger-related costs based on findings that the merger's benefits exceed its costs. Specifically, the Connecticut Public Utilities Regulatory Authority has approved CL&P's recovery of distribution merger-related costs in retail electric rates in Connecticut, while the Massachusetts Department of Public Utilities has approved NSTAR Gas's recovery of gas merger-related costs in retail gas service rates in Massachusetts.

In support of this filing, Eversource Service has prepared a detailed study showing the merger-related costs and savings by cost category. This study shows that during the period 2010 through September 30, 2015,[3] the merger achieved quantifiable enterprise-wide net customer savings of $114.9 million ($239.3 million in savings - $124.4 million in costs), with net customer savings for transmission customers of $21.3 million ($58.7 million in transmission merger savings - $37.4 million in transmission merger costs). Consistent with Commission requirements, and as detailed below, these net savings figures reflect Eversource's determinations of the amount of savings that have already been achieved. But it is noteworthy that these net savings will only continue to accrue in the years to come such that the surplus of savings over costs will continue to grow, with

[3] A September 30, 2015 cut-off date for the merger-related costs and savings was originally selected in order to provide the Commission with the most current data while allowing for sufficient time to facilitate the preparation of this filing. On December 9, 2015, the Connecticut Public Utility Regulatory Authority ("CT PURA") re-opened its Docket No. 12-01-07RE01 for the limited purpose of reviewing CL&P's transaction and integration costs resulting from the NU and NSTAR merger, and to determine whether the proposed FERC filing is consistent with or in conflict with the Settlement Agreement previously approved by CT PURA. As a result, Eversource placed the instant filing on hold. Based on its review of relevant exhibits and testimony regarding merger-related costs and savings, the CT PURA issued a Final Decision on February 19, 2016, concluding, *inter alia*, that the "[a]llocation for transmission-merger-related costs was done correctly" and such costs are "legitimate A&G costs based on actual amounts for expense items under specific FERC accounts." Application for Approval of Holding Company Transaction Involving Northeast Utilities and NSTAR, Docket No. 12-01-07RE01, Decision at 1, 8-9 (Feb. 19, 2016) (available at: http://www.dpuc.state.ct.us/FINALDEC.NSF/0d1e102026cb64d98525644800691cfe/d183b9f6a6e155a285257f61005d6a60/$FILE/120107RE01-021916.docx).

projected enterprise-wide savings of approximately $1 billion and transmission savings of $279 million by 2022. *See* Testimony of Ms. Vaughan, Exhibit No. ES-100, Section I.

Eversource Service respectfully requests that the Commission approve the transmission cost recovery requested in this filing and grant an effective date of June 1, 2016. As explained below, Eversource Service requests that the Eversource Companies be allowed to amortize and recover the transmission merger-related costs over a one-year period. If this request is granted, Eversource Service will waive the recovery of carrying charges on transmission merger-related costs back to the date the costs were incurred and will not request inclusion of the unamortized balance in the Eversource Companies' transmission rate base.

In the alternative, if the Commission denies the one-year amortization period, Eversource Service requests that the Commission allow the Eversource Companies to amortize and recover the transmission merger-related costs over a three-year period, with recovery of carrying charges on transmission merger-related costs and inclusion of the unamortized balance in transmission rate base. Eversource Service has included tariff amendments for its Proposed Cost Recovery Mechanism one-year amortization period proposal (designated as Option A in eTariff), as well as tariff amendments for the Alternative Cost Recovery Mechanism three-year amortization proposal (designated as Option B in eTariff),[4] in clean and redlined form.[5]

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[4] These tariff amendments are being submitted to conform with the Commission's eTariff requirements as to effective dates of amendments. Federal Energy Regulatory Commission, Office of the Secretary, Implementation Guide for Electronic Filing of Parts 35, 154, 284, 300,

II. CONTENTS OF THIS FILING

In addition to this Transmittal Letter, this filing also includes the following documents:

1. Appendix A – Prepared Direct Testimony and Exhibits of Christine L. Vaughan (description of the merger-related customer benefits and merger-related savings) (Exhibit Nos. ES-100 through ES-121);

2. Appendix B – Prepared Direct Testimony and Exhibits of Lisa M. Cooper (description of the merger-related costs, tariff revisions, and revenue impact statements) (Exhibit Nos. ES-200 through ES-226);

3. Appendix C – Prepared Direct Testimony and Exhibits of Michael P. Synan (description of merger-related benefits administration savings) (Exhibit Nos. ES-300 through ES-301);

4. Appendix D – Attestation required by 18 C.F.R. § 35.13(d)(6);

5. Appendix E – Proposed Protective Agreement for confidential filing;

6. Tariff revisions to Section II of the ISO-NE Open Access Transmission Tariff ("OATT") Attachment F, Schedule 1 Appendix A, Schedule 21-NSTAR Attachments D and F, and Schedule 21-ES Attachments ES-H and ES-I (clean and redlined) for the one-year amortization proposal (Proposed Cost Recovery Mechanism); and

7. Tariff revisions to Section II of the ISO-NE OATT Attachment F, Schedule 1 Appendix A, Schedule 21-NSTAR Attachments D and F, and Schedule 21-ES Attachments ES-H and ES-I (clean and redlined) for the alternative three-year amortization proposal (Alternative Cost Recovery Mechanism).

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and 341 Tariff Filings (Sept. 11, 2015). These tariff amendments do not include certain incremental tariff changes that are pending, but not yet effective, in Eversource Energy Service Company, Docket No. ER16-116. Eversource Service commits that it will make conforming eTariff filings if necessary, consistent with Commission rules.

[5] The Eversource Companies are transmission providers providing open access transmission service and recovering their revenue requirements under the ISO New England, Inc. ("ISO-NE") Transmission, Markets and Services Tariff ("ISO-NE Tariff"). This filing is being submitted through the eTariff system by ISO-NE on behalf of the Eversource Companies given ISO-NE's capacity as administrator of the ISO-NE Tariff in the eTariff system.

III. BACKGROUND

A. Description of Eversource Energy

Eversource Energy is a public utility holding company doing business in New England. Eversource Energy has six main utility operating subsidiaries: CL&P, NSTAR Electric, PSNH, WMECO, NSTAR Gas, and Yankee Gas. Eversource Energy's electric and gas service territories cover almost 15,000 square miles, and its utilities serve approximately 3.6 million electric and natural gas retail customers in over 620 cities, towns and communities. As of the end of 2014, Eversource Energy's utilities own 4,288 circuit and cable miles of overhead and underground electric transmission and 65,266 pole miles and conduit bank miles of distribution.

Eversource Service is a service company subsidiary of Eversource Energy that provides centralized corporate, financial, accounting, legal, information systems and other general services to Eversource Energy subsidiaries, including the Eversource Companies.

B. Description of the Merger and Merger Order

On January 7, 2011, in Docket No. EC11-35-000, NSTAR and NU filed under sections 203(a)(1) and 203(a)(2) of the FPA to merge into one entity. The joint application requested authorization of the proposed transaction by which NSTAR would become a wholly-owned subsidiary of NU through a two-step process that was set forth in the Agreement and Plan of the Merger, as amended, that was filed with the Commission. At the time of the merger filing, NSTAR was a public utility holding company that had two primary utility subsidiaries, NSTAR Electric and NSTAR Gas.[6] Legacy NSTAR at the time delivered electricity to over 1.1 million customers in Massachusetts, and delivered natural gas to nearly 300,000 gas customers in Massachusetts.

At the time of the merger filing, Northeast Utilities' utility operating company subsidiaries were CL&P, PSNH, WMECO, and Yankee Gas.[7] Northeast Utilities was a public utility holding company, and its utility operating company subsidiaries provided retail electric service to approximately 1.9 million customers in Connecticut, New Hampshire, and Massachusetts, as well as retail natural gas service to approximately 200,000 customers in Connecticut.

Under the terms of the transaction, NSTAR became a wholly-owned subsidiary of Northeast Utilities. *See* Merger Order at P 17. The Commission thoroughly examined the filing made by Northeast Utilities and NSTAR and approved the transaction on July 6, 2011. *See id.* at Ordering Paragraph A.

In its Merger Order, consistent with Northeast Utilities' and NSTAR's commitment in the merger filing, the Commission instituted a five-year hold harmless requirement. While in approving the hold harmless commitment the Commission directed the merging parties to not include their merger-related costs in their rates as

[6] "Legacy NSTAR" refers to NSTAR and all of its subsidiaries prior to the merger. "Legacy NSTAR Electric" refers to NSTAR Electric prior to the merger.

[7] "Legacy NU" refers to Northeast Utilities and all of its subsidiaries prior to the merger. "Legacy NU Companies" refers to CL&P, PSNH and WMECO prior to the merger. "Legacy Companies" refers collectively to the Legacy NU Companies and Legacy NSTAR Electric.

incurred, the Commission also made clear that the merging parties' transmission customers could be required to pay the applicants' merger-related costs at a later date if, within five years of the date of the merger, the applicants submitted a Section 205 filing with the Commission that demonstrated that the merger-related savings exceeded the merger-related costs. Specifically, the Commission stated:

> If Applicants seek to recover transaction-related costs in an existing formula rate that allows for such recovery within the next five years, then that compliance filing must be filed in the section 205 docket in which the formula rate was approved by the Commission, as well as in the instant section 203 docket. We also note that, if the Applicants seek to recover transaction-related costs in a filing within the next five years whereby it is proposing a *new* rate (either a new formula rate or a new stated rate), then that filing must be made in a *new* section 205 docket as well as in the instant section 203 docket. The Commission will notice such filings for public comment. In such filings, Applicants must: (1) specifically identify the transaction-related costs they are seeking to recover, and (2) demonstrate that those costs are exceeded by the savings produced by the transaction, in addition to any requirements associated with filings made under section 205. Such a hold harmless commitment will protect customers' wholesale and transmission rates from being adversely affected by the Proposed Transaction.

Merger Order at P 63 (internal citations omitted) (emphasis in original). In this filing, Eversource is seeking to recover these merger-related costs. These costs were only excluded from charges to the customers at the time they were incurred due to the Commission's adoption of Eversource's hold harmless commitment that specifically permitted recovery of the costs upon a proper showing in a future filing. This filing makes such a showing.[8]

C. The Merger Has Provided Multiple Benefits to Customers

As outlined above, the merger has been very beneficial to Eversource's customers. One of the key benefits of the merger is the reduction in costs that Eversource realized as a result of the merger. As of September 30, 2015, the merger has produced enterprise-wide merger-related savings of $239.3 million, as compared to $124.4 million of merger-related costs. These savings will only continue to accrue in the years to come such that the surplus of savings over costs will continue to grow, with projected enterprise-wide savings of approximately $1 billion by 2022. *See* Testimony of Ms. Vaughan, Exhibit No. ES-100, Section I.

Since the consummation of the merger, Eversource has experienced substantial decreases in its Non-Fuel electric O&M expenses, with declines in its Non-Fuel electric O&M expense[9] between 2011 and 2014 of approximately 7.2%. This decline for Eversource stands in marked contrast to the experience of other electric utilities over the same time period. As shown in the graph on Page 4 of this Transmittal Letter, Non-Fuel

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[8] In view of the fact that Eversource Service is submitting rate schedule changes to implement its request, Eversource is submitting its filing in a new Section 205 proceeding. However, as described in Section IV.B., these merger costs are A&G costs that are otherwise includible in the existing formula rates and thus, Eversource Service is submitting the filing in the existing Section 205 dockets that approved these existing formula rates as well. Eversource Service is also submitting the filing in the existing Section 203 docket for informational purposes.

[9] To provide an appropriate comparison, O&M costs such as the cost of purchased power and uncollectibles have been excluded. *See* Testimony of Ms. Vaughan, Exhibit No. ES-100, Section IV.C.

electric O&M costs for these utilities increased on average approximately 7.2% over the same period in which Eversource's Non-Fuel electric O&M expenses *decreased* approximately 7.2%.[10]

Service to Eversource customers has markedly improved as a result of its expanded service territory and significant geographic diversity. These service improvements are evidenced by reductions in average outage duration and frequency. *See* Testimony of Ms. Vaughan, Exhibit No. ES-100, Section III. The combined expertise, financial capabilities and bench strength of the two organizations has resulted in Eversource's ability to creatively address regional problems.[11] Finally, Eversource Energy's financial condition improved as a result of the merger. Eversource Energy now holds the highest utility holding company credit rating in the nation (A), and the Eversource Companies' average cost of debt has decreased from 5.06% in 2012 to 4.69% in 2014 (savings from which were passed on to customers). *See* Exhibit No. ES-117.

In addition to these enterprise-wide benefits, the merger has created $58.7 million in savings for transmission customers as of September 30, 2015, and is expected to create

[10] These results are corroborated by Eversource's public filings. For example, as stated in Eversource's annual Securities Exchange Commission 10-K filing, total enterprise-wide O&M expense has gone from $1.58 billion in 2012 to $1.33 billion in 2015, a decline of roughly 16%. Vaughan Testimony, Exhibit No. ES-100 at Section IV.C.

[11] For instance, Eversource has partnered with Spectra Energy and National Grid on the proposed Access Northeast gas pipeline expansion and regional LNG storage project, which is designed to further the goals of reducing the cost of electricity and increasing the reliability of the New England electric system to benefit electric customers. Also, an Eversource subsidiary, Northern Pass Transmission LLC, is pursuing siting of a participant-funded transmission project to increase the flow of low-carbon and renewable hydro-electricity from Canada into New England. *See, e.g.*, *Northern Pass Transmission LLC*, 134 FERC ¶ 61,095 (2011).

$279 million in savings for transmission customers by 2022. *See* Testimony of Ms. Vaughan, Exhibit No. ES-100, Sections I, IV; Exhibit No. ES-104. As discussed herein, the results of the merger meet the Commission's requirement that transmission merger-related savings exceed transmission merger-related costs.

D. State Regulatory Agencies and an Independent Audit Have Recognized the Merger's Benefits

In both Connecticut and Massachusetts, retail regulators have reviewed Eversource's merger-related costs and benefits, and have determined that the benefits outweighed the costs. Retail electric distribution customers of CL&P are paying their share of the costs that enabled the merger, after a ruling by CT PURA concluded that those ratepayers received benefits that exceeded the costs of the merger. *See Application of the Connecticut Light and Power Company to Amend Rate Schedules,* CT PURA Docket No. 14-05-06, Dec. 17, 2014 Final Order at 156[12] (approving recovery of approximately $25 million in CL&P distribution merger-related costs from CL&P electric distribution customers and finding that "the merger has provided benefits to customers which exceed the costs to achieve those reductions"). None of the eight intervenors in the CT PURA docket challenged CL&P's contention that merger-related savings exceeded the merger-related costs. *See id.* at 156 (noting that "[n]o party addressed [the merger savings issue] in its brief or reply brief"). Further, CT PURA recently reviewed relevant exhibits regarding the merger-related costs and savings

[12] Available at: http://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/641c4d6050565a1a85257db10064de71?OpenDocument.

information and concluded that the "[a]llocation for transmission merger-related costs was done correctly," and such costs are "legitimate A&G costs based on actual amounts for expense items under specific FERC accounts."[13]

Similarly, NSTAR Gas's request to the Massachusetts Department of Public Utilities ("MA DPU") in Docket No. 14-150 that its Massachusetts gas customers pay for their share of merger-related costs was approved by the MA DPU. *Petition of NSTAR Gas Co.*, D.P.U. 14-150, Oct. 30, 2015 Order at 132[14] (approving recovery of approximately $5 million in NSTAR gas merger-related costs and finding that "the Company has demonstrated that its merger-related savings exceed its merger-related costs"). The MA DPU Petition was also supported by the Massachusetts Department of Energy Resources (a department of the Massachusetts Executive Office of Energy and Environmental Affairs), who stated that "the record evidence indicates that the actual merger-related savings are on track with its projected savings and, therefore, the Company should be allowed to recover its merger-related costs." Initial Brief of Massachusetts Department of Energy Resources at 4, D.P.U. 14-150 (July 21, 2015).

The cost support used in Connecticut and Massachusetts (known as the "Merger Integration Reports") is attached to the testimony of Ms. Vaughan as Exhibit Nos. ES-

[13] *Application for Approval of Holding Company Transaction Involving Northeast Utilities and NSTAR*, Docket No. 12-01-07RE01, Decision at 1, 8-9 (Feb. 19, 2016) (available at: http://www.dpuc.state.ct.us/FINALDEC.NSF/0d1e102026cb64d98525644800691cfe/d183b9f6a6e155a285257f61005d6a60/$FILE/120107RE01-021916.docx).

[14] Available at: http://web1.env.state.ma.us/DPU/FileRoomAPI/api/Attachments/Get/?path=14-150%2f14150_Order_103015.pdf.

101 and ES-102. The cost support in the Merger Integration Reports utilized a "Net Benefits Analysis" approved by the MA DPU and CT PURA that applied a methodological approach of a recognized industry expert on business consolidation. *See* Exh. JP-1 (Supplemental) at 12-13, MA DPU Docket No. 10-170[15]; *see also Joint Petition for Approval of Merger between NSTAR and Northeast Utilities*, MA DPU 10-170, April 4, 2012 Order at 57[16] ("The Net Benefits Study provides a detailed quantification of expected costs and savings of the Proposed Merger") (citing Exhs. JP-1 and JP-3); Vaughan Testimony, Exhibit No. ES-100 at Section IV.A. Exhibit No. ES-103 includes an updated Merger Integration Report with data through September 30, 2015 that will be filed with the CT PURA as a compliance requirement of the CT PURA merger approval (Docket No. 12-01-07). The updated Merger Integration Report is based on actual data for the historical period (through September 30, 2015) and includes projections for the period after September 30, 2015. This filing builds on the same support used in the Merger Integration Reports to demonstrate that transmission savings associated with the merger exceed transmission merger-related costs.

Finally, a 2015 Management Audit of CL&P performed by Sage Management Consultants contained multiple findings that the merger successfully integrated the functions of Legacy NU and Legacy NSTAR, created efficiencies, and achieved savings.

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[15] Available at: http://web1.env.state.ma.us/DPU/FileRoomAPI/api/Attachments/Get/?path=10-170%2f4711jpst.pdf.

[16] Available at: http://web1.env.state.ma.us/DPU/FileRoomAPI/api/Attachments/Get/?path=10-170%2f4412dpuord.pdf.

See, e.g., Exhibit No. ES-121 at 41,188 (discussing the cost savings and cost efficiencies achieved by the merger); *id.* at 5, 41-42 (discussing the successful integration of Legacy NU and Legacy NSTAR). *See also* Exhibit No. ES-100 at Section III.

IV. RECOVERY OF JURISDICTIONAL MERGER-RELATED COSTS THROUGH TRANSMISSION RATES IS APPROPRIATE IN THIS CIRCUMSTANCE

As demonstrated below and in the testimony of Ms. Vaughan, Ms. Cooper, and Mr. Synan, the Eversource Companies satisfy the Commission's requirements for transmission merger cost recovery by specifically identifying the costs they are seeking to recover (including the demonstration of appropriate procedures and controls for those costs), and by documenting the substantial savings that have resulted from the merger. The analysis shows that the transmission merger-related savings that the Eversource Companies have already realized exceed transmission merger-related costs by a substantial margin. These merger-related savings continue to grow, while merger-related costs have declined substantially. *See* Exhibit No. ES-103, Table 1.

In addition, while Eversource Service has not included any post-September 2015 merger-related savings in its comparative analysis, it is worth noting that projected post-September 2015 merger-related savings outstrip the limited amount of projected post-September 2015 merger-related costs by a very wide margin. By 2022, ten years following the merger, cumulative merger benefits are expected to exceed cumulative merger-related costs by a factor of eight to one. *See* Testimony of Ms. Vaughan, Exhibit No. ES-100, Section I; Exhibit No. ES-103, Table 1.

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A. FERC Requirements for Merger Cost Recovery

In various merger orders, the Commission has set out the standards by which companies may make a request for merger-related cost recovery. The Commission allows recovery of merger-related costs in a Section 205 filing by: (1) identifying the merger-related costs applicants are seeking to recover; and (2) demonstrating that those costs are exceeded by the savings produced by the merger. *See* Merger Order at P 63; *Exelon Corp.*, 149 FERC ¶ 61,148 at PP 106-07 (2014); *Wisc. Energy Corp,. Integrys Energy Grp., Inc*., 151 FERC ¶ 61,015 at P 56 (2015); *Pennsylvania Elec. Co.*, 154 ¶ 61,109 at P 49 (2016).

Applicants must demonstrate their use of appropriate internal controls and procedures for proper identification, accounting and rate treatment of all merger-related costs. *Exelon*, 149 FERC ¶ 61,148 at P 150. Types of recoverable costs include both transaction-related costs (incurred to explore, agree to, and consummate the merger), as well as transition-related costs (incurred to integrate individuals and assets into the acquiring utility, and costs to achieve "merger synergies"). *Exelon Corp.*, 149 FERC ¶ 61,148 at PP 149-50.

Merger-related savings must be realized prior to, or concurrent with, any authorized recovery of merger-related costs. *Wisc. Energy Corp., Integrys Energy Grp., Inc*., 151 FERC ¶ 61,015 at P 56 (citing Audit Report of National Grid, USA, Docket No. FA09-10-000 (Feb. 11, 2011) at 55; *Ameren Corp*., 140 FERC ¶ 61,034 at PP 36-37 (2012)). The Commission has acknowledged that "showing [merger-related] savings and benefits may be difficult" due to the subjectivity of savings analyses, *Exelon*, 149 FERC ¶ 61,148 at P 107, and that savings showing requirements can be satisfied through "reasonable documentation and estimates of the costs avoided." *Id*.

In this filing, Eversource Service demonstrates that it has met each of the Commission's conditions to request merger cost recovery on behalf of the Eversource Companies, and has applied conservative criteria to determine the merger-related costs and savings. Based on Eversource Service's satisfaction of the Merger Order, as well as its provision of evidentiary support and reasonable documentation for its merger-related costs and savings, Eversource's recovery of its merger-related costs is consistent with its hold harmless commitment. In addition, since Eversource's merger-related costs are more than offset by its merger-related savings, and the Eversource Companies recover their non-merger related costs under a Commission-approved formula rate, the resulting new rate is just and reasonable in light of all factors affecting the rate.

B. Identification of Merger-Related Costs

Eversource determined its merger-related costs beginning in 2010 (when the merger was beginning to be evaluated, and merger-related costs were first incurred) and continuing through September 30, 2015. The merger-related costs are comprised of transaction costs (i.e., legal, banking and other costs incurred to evaluate, structure and close the transaction); and transition costs (i.e., costs necessarily incurred to determine the steps necessary to be ready to run the combined entity on day one, followed by integration efforts to identify and achieve synergies from the merger). Eversource's specification of merger-related costs is conservative – it is only seeking to recover a portion of its transmission merger-related costs in this filing and is foregoing recovery of the transmission portion of goodwill, executive severance and retention costs, and branding costs.

On an enterprise-wide basis, Eversource incurred $124.4 million in incremental merger-related costs and is seeking recovery of the transmission-related portion of this amount in this filing. Of these $124.4 million in costs, $68 million are transaction costs and $56.4 million are transition costs. In addition to these incremental costs, the Eversource Companies also incurred non-incremental transmission merger-related internal labor costs of $1.4 million. As Ms. Cooper explains in her testimony, all of these costs are Administrative and General ("A&G") expenses that would normally be recoverable in the Eversource Companies' formula rates but for the Eversource Companies' hold harmless commitment. The Eversource Companies also anticipate incurring a relatively limited amount of future transmission merger-related costs; these are capped at $1.5 million (discussed below). The total transmission merger-related costs are $38.9 million (including the $1.5 million in estimated future transmission merger-related costs). *See* Testimony of Ms. Cooper, Exhibit No. ES-200, Section III. Other than internal labor and estimated future transition costs, the categories of transaction and transition costs discussed below are the same as those presented in the state proceedings for recovery of Eversource's retail merger-related costs. *See* Exhibit Nos. ES-101 and ES-102.

1. Eversource Properly Identified and Accounted for Both Transaction and Transition Merger-Related Costs

In accordance with its hold harmless commitment to the Commission, Eversource instituted controls to segregate merger-related costs so that they could be both tracked and excluded from the customers' rates. Prior to the consummation of the merger on April 10, 2012, merger-related incremental costs (both transaction merger-related costs and transition merger-related costs) for Legacy NU were recorded to the Legacy NU parent company books. Legacy NU used a separate activity code, "ODEDT," to identify and track merger-related costs. The Legacy NU Accounting Department monitored these costs to ensure they were appropriately recorded. Incremental transaction merger-related costs for Legacy NSTAR were recorded to the NSTAR parent company books while incremental transition merger-related costs were recorded to Legacy NSTAR Electric's books. Beginning in 2011, Legacy NSTAR used a unique subaccount (subaccount 39) to identify and track merger-related costs. The Legacy NSTAR Accounting Department monitored these costs to ensure they were appropriately recorded.

In addition, in early 2011, Legacy NU and Legacy NSTAR worked with Oliver Wyman, a leading global management consulting firm with specialized expertise in organization transformation, to prepare for Day 1 readiness and integration planning for the merged company. This process included documenting the business functions at Legacy NU and Legacy NSTAR. Functional Integration Teams ("FIT") were established and subject matter experts identified at each company. Legacy NU and Legacy NSTAR provided FIT members detailed guidance on how to track merger-related costs. As indicated above, Legacy NU used a separate activity code, "ODEDT," and Legacy NSTAR used a unique subaccount (subaccount 39) to identify and track merger-related costs. Post-merger, all incremental merger-related costs were recorded to the Eversource parent company books and monitored by the Accounting Department to ensure they were appropriately recorded. In 2014, Eversource implemented a new accounting system that established similar activities as described above to identify and track remaining merger-related transition costs.

2. Identification of Transaction Costs

Eversource's transaction costs to consummate the merger fall into these categories: bankers' fees; lawyers' fees; registration fees; consulting fees; and regulatory process costs. Each of these categories of costs, as well as internal costs, is described below. Consistent with Commission requirements, these transaction costs include external third-party costs for legal, consulting, and professional services incurred to consummate the merger. These costs are detailed in the testimony of Ms. Cooper, Exhibit No. ES-200, Section III.B., and associated Exhibit Nos. ES-202 through ES-208.

a. Bankers' Fees

Bankers' fees were incurred between 2010 and 2012 in connection with the merger. These fees totaled $48.0 million and were for financial advisory services associated with the proposed transaction, including financial analyses and formulation of negotiation strategies. These costs are detailed in the testimony of Ms. Cooper and associated Exhibit No. ES-202.

b. Lawyers' Fees

Fees for lawyers and associated services were incurred from 2010-2012 and totaled $11.7 million. These fees include the professional services of law firms and legal consultants, as well as legal process costs incurred to structure and close the transaction. These costs are detailed in the testimony of Ms. Cooper and associated Exhibit No. ES-203.

c. Registration Fees

Registration fees were incurred in 2010 and 2011 and totaled $2.1 million. These fees were paid to companies that assisted in the registration of the merged company, including services to register with the Securities Exchange Commission ("SEC"), deliver shareholder materials, and hold shareholder meetings. These costs are detailed in the testimony of Ms. Cooper and associated Exhibit No. ES-204.

d. Consultant Fees

Consulting costs were incurred in 2010 and 2011 and totaled $1.4 million. These costs included fees that were paid to companies to analyze tax and accounting issues arising from the proposed transaction, and to provide public and investor relations services in connection with the merger. These costs are detailed in the testimony of Ms. Cooper and associated Exhibit No. ES-205.

e. Regulatory Process Costs

Regulatory process costs were incurred in 2010 and 2011 and totaled $4.7 million. These costs were paid to companies for legal fees in connection with the regulatory proceedings for the merger, and consulting services related to witness preparation and regulatory filing preparation. These costs are detailed in the testimony of Ms. Cooper and associated Exhibit Nos. ES-206 through ES-208.

f. Non-Incremental Internal Labor Costs

Legacy NU and Legacy NSTAR originally included non-incremental internal labor costs that were recorded on their transmission owning operating companies' books in activity "ODEDT" and subaccount 39, respectively, and they were therefore included in their formula rates. This was based on their view that the hold harmless commitment did not apply to non-incremental transition costs (i.e., salaries for employees that would be the same whether or not those employees were involved in merger-related activities). The Commission appeared to support this interpretation in *BHE Holdings Inc*., 133 FERC ¶ 61,231 at P 24 (2010), which upheld the applicant's commitment to hold its transmission customers harmless by excluding only merger-related costs in Account No. 923 (Outside Services) from the formula rate. However, as a result of the Commission's audit of Legacy NSTAR Electric's 2011 formula rate charges in Docket No. FA12-10-000, Legacy NSTAR Electric refunded to transmission customers approximately $0.4 million of non-incremental internal labor costs that Legacy NSTAR Electric had recorded to subaccount 39 and had included in its formula rate. The Legacy NU Companies followed this same process and refunded to transmission customers approximately $1.0 million of non-incremental internal labor costs that the Legacy NU Companies had recorded to activity ODEDT and had included in their formula rate.[17] All of these non-incremental internal labor costs that were removed from the formula rates and refunded to customers are included in the transmission merger-related costs for which Eversource seeks recovery in this proceeding. These costs are additional to the merger-related costs that Eversource identified in the Merger Integration Report. Non-incremental internal labor merger-related costs are identified in Exhibit No. ES-209.

3. Identification of Transition Costs

The transition costs that have been incurred post-merger to create a unified organization fall into four categories: separation program costs; system integration costs; other transition costs; and separation assistance costs. *See* Testimony of Ms. Cooper, Exhibit No. ES-200, Section III.C (discussing transition costs, including the management process for identification and tracking of merger-related transition costs). Consistent with Commission requirements, these categories include costs to achieve synergies from the merger. In addition, Eversource anticipates a relatively small amount of additional transition costs in these categories in the future. As explained below, these projected

[17] Although Legacy NSTAR Electric and the Legacy NU Companies agreed to refund these amounts, Eversource recognizes that this is one of the issues various entities have taken different positions on in connection with the Commission's proposed Policy Statement on Hold Harmless Commitments in Docket No. PL15-3-000.

costs, when combined with the merger-related costs incurred through September 30, 2015, are fully offset by the realized merger-related savings.

a. Separation Program Costs

Severance costs for non-executives were incurred in 2012-2014 and totaled $32.5 million.[18] These costs were comprised of conventional severance payments, outplacement costs, and Consolidated Omnibus Budget Reconciliation Act ("COBRA") and medical insurance costs. These costs are detailed in the testimony of Ms. Cooper and associated Exhibit No. ES-210.

b. System Integration Costs

System integration costs were incurred to design a new organizational structure, and to integrate and consolidate previous platforms. System integration costs were incurred from 2013-2015 and totaled $13.3 million. Such costs resulted in standardization of programs (e.g., integration of human resources processes, sharing of applications and business processes across the organization), and integration of disparate applications (including integration of email and remote access programs). These costs are detailed in the testimony of Ms. Cooper and associated Exhibit No. ES-211.

c. Other Transition Costs

Various other transition costs were incurred from 2010-2015 to provide services and systems necessary for the integration of Legacy NU and Legacy NSTAR. These costs totaled $10.5 million. Examples of these costs include costs to print merger

[18] Eversource is not seeking recovery of executive severance costs.

presentations, phone system changes, shareholder correspondence, and consultant costs for review of such items as facility use and day one connectivity. These costs are detailed in the testimony of Ms. Cooper and associated Exhibit No. ES-212.

d. Separation Assistance Costs

Separation assistance costs were incurred to provide employees with outplacement and career transition services. These separation program costs were incurred in 2012 and totaled $0.2 million. These costs are detailed in the testimony of Ms. Cooper and associated Exhibit No. ES-213. As Ms. Vaughan describes in her testimony, Eversource's separation assistance services provided broad support for transitioning and retiring employees, including one-on-one job search coaching with guidance on networking, interviewing, resume writing, and job leads, as well as individualized wellness and life balance advice. Three quarters of transitioning employees took advantage of these services since the merger occurred in 2012. Testimony of Ms. Vaughan, Exhibit No. ES-100, Section IV.B.1.

e. Future Costs

Eversource expects that it will incur a relatively small amount of additional transmission merger-related costs subsequent to September 30, 2015, the cut-off date for the merger-related costs and savings included in this filing. Eversource anticipates that these costs will not exceed $1.5 million. Based on the enterprise-wide savings for the merger of $239.3 million, and overall transmission savings for the merger of $58.7 million (*see* Section IV.C, below), these expected future costs, when combined with the transmission merger-related costs outlined above, are still far exceeded by the benefits of the merger. Therefore, Eversource Service requests that it be allowed to include in transmission rates future transmission merger-related costs of up to $1.5 million. Eversource Service will submit a compliance filing no later than thirty days following the April 10, 2017 close of the hold harmless period, identifying each such cost. If there are fewer future transmission merger-related costs than estimated, Eversource Service will only pass through to transmission customers the actual costs. To the extent future transmission merger-related costs exceed the $1.5 million cap, Eversource Service will not include these costs in transmission rates without submitting a Section 205 filing for recovery of any additional costs in excess of the cap.

C. Allocation of Merger-Related Costs to the Transmission Function

For allocation purposes, merger-related costs can be viewed as falling into two broad categories: (1) incremental costs that were external to Eversource (e.g., bankers' fees), and (2) an allocation of Eversource's non-incremental internal costs (e.g., an allocation of the salary of an employee who worked on the merger but who would have received that salary regardless of the merger). Eversource functionalized incremental merger-related costs using gross plant ratios. As Ms. Cooper explains in her testimony, this asset-based allocation is a reasonable methodology, in view of the fact that the costs were incurred in order to achieve the merger of the corporate assets. In addition, this is the same allocation methodology that was approved in the state proceedings. The consistent use of allocations between the state proceedings and this proceeding is important and necessary to avoid any potential over or under cost recovery. Eversource's non-incremental internal costs (which were not included in state filings) were allocated to the transmission function using the same methodology in the Eversource Companies' transmission formula rates.[19]

As a result of these allocation methods, Eversource determined that $37.4 million of the $124.4 million in merger-related costs that the Eversource Companies incurred through September 30, 2015 were transmission-related. This represents approximately 30% of Eversource's enterprise-wide costs. As explained in the following section, these transmission merger-related costs were more than offset by transmission merger-related savings.

D. Identification of Merger-Related Savings

Eversource analyzed merger-related savings from April 2012 through September 30, 2015. Consistent with Commission requirements, Eversource has identified its savings in multiple categories by applying reasonable savings calculations and has documented these savings based on the information available for each category. Eversource examined the effects of the merger on the following functional areas: corporate and administrative labor, benefits administration, information systems ("IT"), insurance, professional services, contract services, external directors/trustees fees, materials and supply procurement, administrative and general overhead, association dues,

[19] For both Legacy NU and Legacy NSTAR, the internal costs were incurred at the service company level. *See* Testimony of Ms. Cooper, Exhibit No. ES-200, Section III.D., for discussion of allocation of service company costs.

shareholder services, advertising,[20] facilities, vehicles, credit facilities, inventory, and energy sourcing. The savings calculations and support for each of these categories is discussed in the testimony of Ms. Vaughan and Mr. Synan (Exhibit Nos. ES-100 and ES-300). The savings calculations were calculated in the same manner as they were calculated in the Merger Integration Reports filed in the state proceedings. The savings were determined in each year in which the cost reduction occurred, and then escalated by an appropriate inflation rate in order to reflect the savings achieved. Eversource used a general inflation rate for all cost categories except wages and health costs. Health costs have experienced higher than average inflation rates for many years, so a health cost inflation index was used for these costs; Eversource's historical merit wage increase rate was used for wages.

The merger-related savings examination showed that Eversource realized quantifiable savings in the vast majority of these functional categories (Eversource did not specifically quantify savings in the facilities, vehicles, credit facilities, inventory and energy sourcing areas). As shown below and in the testimony of Ms. Vaughan and Mr. Synan, the enterprise-wide net customer savings for the examined functional areas totals $114.9 million.

1. Corporate and Administrative Labor

Following the close of the merger, the Corporate and Administrative function of the newly merged entity was evaluated and reorganized to eliminate redundant positions,

[20] Advertising expenses are not included as a savings category in this filing.

leading to staffing reductions. These reductions were achieved through the reduction of employee positions and through attrition of shared services employees. Eversource quantified the fully loaded annual savings (including benefits) associated with actual merger-related employee reductions. In addition, if positions opened up in shared services functions due to employee corporate attrition, and those positions were eliminated rather than re-filled due to the fact that other resources existed within the combined company to absorb the workload of the former employees, then those positions were considered a direct result of the merger and associated savings were quantified. *See* Testimony of Ms. Vaughan, Exhibit No. ES-100, Section IV.B.1; Exhibit No. ES-105. In calculating the merger-related attrition, Eversource first added the number of new hires, and then subtracted the number of employee exits, to ensure Eversource only captured the net merger-related attrition. As of September 30, 2015, merger-specific reductions and merger-related attrition accounted for the reduction of 383 positions. As discussed in the testimony of Ms. Vaughan and corresponding Exhibit No. ES-105, the staffing changes that resulted from the merger produced savings of $122 million, including employee-benefits costs and other indirect expenses associated with labor.

2. Benefits Administration

The merger provided an opportunity for Eversource to create a standard platform of active health and welfare plan designs; leverage the scale of the merged company to market key health and welfare plans; and consolidate vendors for medical, prescription drug, dental, vision, life insurance and employee assistance programs through this market process. As a result of consolidating vendors for medical, prescription drug, dental, vision, life insurance and employee assistance programs, Eversource was able to realize significant savings to both its active health expense and retiree health expense. This was due to the substantially increased size of the new entity, which gave Eversource greater buying power and allowed the merged organization to obtain more favorable terms with benefits carriers. These favorable terms led to, among other savings, meaningful reductions in the administrative costs incurred by Eversource for its health, vision, and dental plans. As the MA DPU observed:

> [W]ith the merger of Northeast Utilities and NSTAR Gas, the Company created a standard platform of active health and welfare designs, leveraged the scale of the merged company to market key health and welfare plans, and consolidated vendors for medical, prescription drug, dental, vision, life insurance, and employee assistant programs. Because of the health plan provider's extensive network, most employee claims are incurred on an in-network basis, which is more cost effective for employees and the Company.[21]

The audit of CL&P confirmed the significant savings realized in the area of Benefits Administration.[22] As discussed in the testimony of Mr. Synan (Exhibit No. ES-300) and corresponding Exhibit No. ES-301, Eversource has realized $57.5 million in enterprise-wide savings in the area of benefits administration.

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[21] MA DPU 14-150 Order at (Oct. 30, 2015) (internal citations omitted).

[22] *See* Exhibit No. ES-121 at 188 ("The 2012 merger of NSTAR and NU offered the opportunity for a number of cost savings. The most significant of these was the consolidation of the two company's employee benefits programs.").

3. Information Systems

On account of the merger, Eversource combined two separate Information Technology ("IT") departments (including two IT labor forces, two separate technology platforms, and differing principles and processes) into one functional department with applications that function across all departments and businesses. As part of the merger integration effort, Eversource conducted a comprehensive assessment of the combined company's IT organization, requesting and evaluating bid proposals from multiple IT service providers. As a result of this review, Eversource restructured the IT department by contracting with two consulting companies to provide the majority of IT functions to the newly merged entity. This provided an integrated and centralized approach to IT services, including the implementation of efficiencies and best practices to support the entire post-merger organization. The new restructured IT was organized so that the in-house IT team would focus on management, oversight, and strategic "change the business" work, while day-to-day "service the business" work was shifted to the two new vendors. The IT restructuring led to IT merger-specific labor reductions of 183 positions in 2014 and 2015. Contracting with the new vendors to perform IT services also allowed for the elimination of prior IT services contracts, thus resulting in efficiencies by eliminating duplicative contracts and applications. As discussed in the testimony of Ms. Vaughan (Exhibit No. ES-100, Section IV.B.3.) and corresponding Exhibit No. ES-106, the IT reorganization resulted in savings of $18.2 million.

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4. Insurance

Following the consummation of the merger, Eversource reviewed existing insurance policies and coverage and combined the individual legacy company policies as those policies expired, resulting in better pricing for the combined company than on a stand-alone basis. Thus, the merger provided a unique opportunity to lower the base level of insurance cost for the overall organization through policy consolidation. Combination of the insurance programs also provided the opportunity for Eversource to reassess needed coverage levels and related deductibles based on the loss experience and risk profile of the combined company as compared to the separate stand-alone companies. Due to these factors, Eversource was able to extend its coverage with its carriers over a larger asset and loss experience base, thereby reducing overall cost. As discussed in the testimony of Ms. Vaughan (Exhibit No. ES-100, Section IV.B.4.) and corresponding Exhibit No. ES-107, insurance savings totaled $7.5 million.

5. Professional Services

Following the merger, Eversource worked to consolidate and reduce professional services activities (including corporate procurement credit cards, vendors for payroll services, vendors for staff management, external auditors, research services, call center contracts, and financial reporting services) through economies of scope, elimination of non-recurring duplicate services, and increased utilization of a broader skill base. As discussed in the testimony of Ms. Vaughan (Exhibit No. ES-100, Section IV.B.5.) and corresponding Exhibit No. ES-108, this consolidation and reduction led to professional services savings of $4.3 million.

6. Contract Services

Following the merger, Eversource was able to consolidate and reduce contract service activities through elimination of non-recurring duplicate services and through enhanced economies of scale that the newly merged entity enjoyed. Eversource examined common vendors of both Legacy NU and Legacy NSTAR and consolidated contracts where necessary, frequently obtaining vendor concessions on certain contract provisions due to the merged entity's bargaining power. For many contract services, Eversource conducted a competitive bidding process that resulted in lower costs for the same contract service. As discussed in the testimony of Ms. Vaughan (Exhibit No. ES-100, Section IV.B.6.) and corresponding Exhibit No. ES-109, these changes produced savings of $13 million.

7. External Directors/Trustees Fees

The merger resulted in the combination of the Legacy NU and Legacy NSTAR boards of trustees. Savings were calculated by comparing the costs for the NU and NSTAR Boards of Trustees to the costs for the 2013 post-merger Board. As discussed in the testimony of Ms. Vaughan (Exhibit No. ES-100, Section IV.B.7.) and corresponding Exhibit No. ES-110, these changes produced savings of $3.3 million.

8. Materials and Supply Procurement

Following the merger, Eversource consolidated the procurement contracts of Legacy NU and Legacy NSTAR by evaluating common vendors to both and renegotiating such contracts, realizing savings due to both consolidation of vendors as well as vendor concessions given to Eversource. In addition, cost savings were achieved by competitive bidding processes with existing vendors, resulting in the selection of one post-merger vendor. Eversource also reviewed the materials function across the enterprise, leading to the elimination of over 100 duplicate items, resulting in a lower ongoing material cost. As discussed in the testimony of Ms. Vaughan (Exhibit No. ES-100, Section IV.B.8.) and corresponding Exhibit No. ES-111, these changes produced savings of $8.1 million.

9. Administrative and General Overhead

Following the merger, administrative and general overhead costs (including costs for office supplies, telephone expenses, and employee business expenses) decreased as existing contracts were renegotiated or replaced due to Eversource's increased purchasing leverage, and as corporate personnel were reduced. As discussed in the testimony of Ms. Vaughan (Exhibit No. ES-100, Section IV.B.9.) and corresponding Exhibit No. ES-112, these changes produced savings of $2.1 million.

10. Association Dues

Following the consummation of the merger, Eversource re-evaluated its association dues, professional memberships, and corporate sponsorships/association fees and eliminated certain duplicative dues (such as those for the Edison Electric Institute), as well as dues that were determined after further evaluation to be unnecessary post-merger. As discussed in the testimony of Ms. Vaughan (Exhibit No. ES-100, Section IV.B.10.) and corresponding Exhibit No. ES-113, these changes produced savings of $1.1 million.

11. Shareholder Services

Following the close of the merger, Eversource was able to realize savings in the area of Shareholder Services due to the elimination of duplicative shareholder related activities, such as conducting the annual shareholder meeting, proxy services and payment of stock exchange fees. Additionally, incremental costs incurred per additional shareholder were reduced for the newly formed Eversource Energy due to economies of scale that NU and NSTAR were unable to achieve as standalone companies. As discussed in the testimony of Ms. Vaughan (Exhibit No. ES-100, Section IV.B.11.) and corresponding Exhibit No. ES-114, these changes produced savings of $2.1 million.

E. Allocation of Merger-Related Savings to the Transmission Function

In order to determine the amount of enterprise-wide merger benefits that were related to the transmission function, Eversource performed a benefit allocation that took into account the nature of the benefits that the Eversource Companies realized, and used allocators appropriate to each cost category. These are the same allocation methodologies that were used in the state proceedings. The consistent use of allocations between the state proceedings and this proceeding is important and necessary to avoid any potential over- or under-representation of savings.

Eversource examined each of these 11 categories of merger-related savings discussed above, and functionalized each category taking into account the nature of the savings. For example, labor and benefits savings were functionalized using the wages and salaries ratio, since this ratio best reflects the nature of such cost savings. Contract services savings, on the other hand, were functionalized based on total O&M expenses, since that best represents the nature of contract services cost savings. All of these allocation methods are detailed in the testimony of Ms. Vaughan and associated Exhibit No. ES-116.

V. TARIFF REVISIONS

A. Description of the Eversource Companies' Transmission Rates

The Eversource Companies recover their total transmission revenue requirements through a combination of regional and local rates, both of which are part of Section II of the ISO-NE Tariff ("ISO-NE OATT"). The majority of the costs associated with the regional Pool Transmission Facilities[23] ("PTF") are recovered through Regional Network Service ("RNS") rates. Those rates are calculated under a formula rate included as Attachment F to the ISO-NE OATT. Any NSTAR Electric PTF costs not recovered under RNS rates, as well as the cost of non-PTF, are recovered under Schedule 21-NSTAR of the ISO-NE OATT. Any CL&P, PSNH and WMECO PTF costs not recovered under RNS rates, as well as the cost of non-PTF, are recovered under Schedule

[23] Pool Transmission Facilities are facilities rated 69 kV or above, and are required to allow energy from significant power sources to move freely on the New England transmission network.

21-ES[24] of the ISO-NE OATT. These Schedules contain formula rates that calculate NSTAR Electric's (Schedule 21-NSTAR, Attachments D and F) and CL&P, PSNH and WMECO's (Schedule 21-ES, Attachments ES-H and ES-I) transmission revenue requirements. The revenues that the Eversource Companies receive under the RNS rate are a revenue credit to the Eversource Companies' Schedules 21-NSTAR and 21-ES. The formula rates in ISO-NE OATT Attachment F, Schedules 21-NSTAR Attachments D and F, and Schedule 21-ES Attachments ES-H and ES-I will be referred to as the "Transmission Service Formula Rates."

In addition to recovering their transmission revenue requirements, the Eversource Companies recover their costs for providing Scheduling, System Control and Dispatch Service under ISO-NE OATT Schedule 1, Appendices A (NSTAR) and C (CL&P).[25] The formula rates in ISO-NE OATT Schedule 1, Appendices A and C will be referred to as the "Schedule 1 Formula Rates."

B. Proposed Cost Recovery Mechanism

In order to recover merger costs from their transmission customers at this time, the Eversource Companies are filing revisions to the Transmission Service Formula Rates that provide for the inclusion of the amortization of the merger-related costs allocated to the transmission function ("Transmission Merger-Related Costs") in the Transmission

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[24] The name change of Schedule 21-NU to Schedule 21-ES, and other related name changes therein, was accepted by the Commission in Docket No. ER16-348 on December 22, 2015.

[25] As discussed below and in Ms. Cooper's testimony, no changes are being made to Schedule 1 Appendix C.

Service Formula Rates, and are requesting authorization to establish a regulatory asset in Account No. 182.3 on June 1, 2016 for the Transmission Merger-Related Costs.[26] Although these merger costs are A&G costs that are includible in the formula rate, for Legacy NSTAR Electric, such costs are included in the formula rate on a company-wide basis, and then allocated to the transmission function. Transmission Merger-Related Costs, as defined in this filing, in contrast are *already* functionalized to transmission, so they cannot simply be added to total A&G expense. As a result, two steps are necessary in order to include Transmission Merger-Related Costs in the Transmission Service Formula Rates. First, all merger-related costs authorized for recovery by FERC or by state regulatory order are removed from the definition of *total* Administrative and General Expenses (Merger-Related Costs). Second, Transmission Merger-Related Costs are added as a line item to *Transmission Related* Administrative and General Expense. This ensures that the Transmission Merger-Related Costs are properly functionalized, and not included in the Transmission Formula Rates twice. In addition, because the Transmission Formula Rates only recover the portion of merger-related costs that are

[26] Account 182.3 includes amounts that would be included in net income but for it being probable that the costs would be recovered in rates in a different period, and thus recording these costs to Account 182.3 is appropriate here. This accounting is consistent with the accounting that the Commission approved for Northeast Utilities in Docket No. ER08-149 with respect to RTO start-up costs. *Northeast Utils. Serv. Co.*, 121 FERC ¶ 61,308 (2007). While in that case the expenses were amortized over a three-year rather than a one-year period, in that case Northeast Utilities included carrying charges on the RTO expenses until it commenced their recovery. In view of the Eversource Companies' conditional waiver of carrying charges here, a shorter amortization period is appropriate.

allocable to the transmission function, the Formula Rates do not recover any non-transmission related merger costs recovered in retail rate proceedings.[27]

With respect to the amortization period for transmission merger-related costs, Commission precedent demonstrates that the Commission reviews amortization periods on a case-by-case basis, and that it will shorten the amortization period to a year in order to reduce carrying charges on customers. *See, e.g.*, *PJM Interconnection L.L.C.*, 140 FERC ¶ 61,197 at P 27 (2012) (approving a one-year amortization based on the relatively small amount to be recovered and the avoided carrying charges which would reduce the total amount collected; also noting that amortization periods are reviewed on a case-by-case basis); *S. Cal. Edison Co.* 137 FERC ¶ 61.252 at P 27 (2011) (approving one-year amortization because it would reduce the overall costs by avoiding several years of carrying charges). Eversource Service requests such one-year amortization for its Proposed Cost Recovery Mechanism, as it similarly will reduce overall costs.

In this case, the Eversource Companies are conditionally waiving the recovery of carrying charges, as well as conditionally waiving the inclusion of the unamortized balance in transmission rate base while the amortization proceeds. Both waivers are subject to the condition that the Eversource Companies be permitted to recover their transmission merger-related costs over a one-year period beginning June 1, 2016. This is

[27] Similar changes are being made to the formula rate in ISO-NE OATT Schedule 1, Appendix A (NSTAR), but are not necessary for ISO-NE OATT Schedule 1, Appendix C (CL&P), as this filing pertains to the recovery of A&G expenses, and that formula rate does not contain an A&G component.

a significant concession, because these charges are permissible under standard ratemaking practice in order to reflect the company's capital costs.[28] As noted by the Commission, carrying charges are "simply a way of ensuring that a party receives full compensation for its actual costs, when its recovery of those costs is deferred," and that "[c]ompensation deferred is compensation reduced by the time value of money."[29] In this case, approving a one-year amortization period will not only reduce the carrying charges that customers bear, as it did in the cases cited above, it will eliminate them entirely.

The savings to customers resulting from a one-year amortization are significant. As demonstrated in the testimony of Ms. Cooper and associated Exhibit Nos. ES-214 through ES-219, and ES-220 through ES-226 (revenue impact statements showing the effect of the Proposed Cost Recovery Mechanism and the Alternative Cost Recovery Mechanism), approving the one-year amortization will reduce the costs recovered from transmission customers by $11.3 million, or 30%. *See* Testimony of Ms. Cooper, Exhibit No. ES-200 at Section VI. This warrants approval of the one-year amortization period, consistent with the Commission precedent cited above. Based on the attached testimony and exhibits demonstrating that substantial savings have already been realized by transmission customers, recovery over the one-year period is further justified. Prompt recovery of these costs is also appropriate in view of the fact that the transmission merger-related savings that justify the recovery of the transmission merger-related costs

[28] *See, e.g.*, *Sea Robin Pipeline Co., LLC*, 143 FERC ¶ 61,129 at P 43 (2013); *Northeast Utils. Serv. Co.*, 121 FERC ¶ 61,308; *Union Elec. Co.*, 40 FERC ¶ 61,046 at 61,134 (1987).

[29] *Sea Robin Pipeline Co., LLC*, 143 FERC ¶ 61,129 at P 43.

have already been passed through to customers in the transmission Formula Rates. Amortizing these costs over a period longer than a year will only further separate the benefit incurrence and cost recovery periods.

C. Alternative Cost Recovery Mechanism

In the event that the Commission does not accept the Eversource Companies' proposal to amortize and recover the Transmission Merger-Related Costs over a one-year period, the Eversource Companies propose that the Transmission Merger-Related Costs be amortized over a three-year period, that carrying charges be applied to the Transmission Merger-Related Costs until amortization of the transmission merger-related costs commences,[30] and that the unamortized balance of transmission merger-related costs be included in transmission rate base while the amortization proceeds. In order to accomplish this, the Eversource Companies request that they be permitted to establish a regulatory asset in Account 182.3 on June 1, 2016 for the Transmission Merger-Related Costs, and they be permitted to amortize those costs to the A&G accounts to which the costs would have been recorded but for Eversource's hold harmless commitment. The Eversource Companies request that this amortization commence on June 1, 2016, and the transmission merger-related costs be amortized over a three-year period.

[30] Carrying charges would be compounded semi-annually.

Under this alternative proposal, carrying charges, at the Eversource Companies' Allowance for Funds Used During Construction ("AFUDC") rate,[31] would be added to the transmission merger-related costs until the amortization begins,[32] and the changes to the Transmission Service Formula Rates that are discussed above (for the purpose of including the amortized amounts in the transmission revenue requirement) would still be made. In addition, the Transmission Service Formula Rates would need to be further revised, in order to include the unamortized balance of transmission merger-related costs in rates. To accomplish this, the calculation of "Other Regulatory Assets/Liabilities" in the Transmission Service Formula Rates would be modified to include the Eversource Companies' unamortized balance of merger-related transmission costs recorded in FERC Account No. 182.3 as authorized by FERC.[33]

VI. REVENUE IMPACT

The Eversource Companies have calculated the revenue impact of their Proposed Cost Recovery Mechanism, as well as of their Alternative Cost Recovery Mechanism. These calculations are set forth in the testimony of Ms. Cooper, Exhibit No. ES-200, and corresponding Exhibit Nos. ES-214 through ES-219 and ES-221 through ES-226. These

[31] Commission precedent fully supports the use of a company's AFUDC rate for carrying charges. *See, e.g., N.Y. Indep. Sys. Operator, Inc.*, 151 FERC ¶ 61,004 at P 78 (2015) ("We also grant NY Transco's request to accrue a carrying charge on the regulatory asset using the AFUDC rate."); *Xcel Energy Transmission Development, LLC*, 149 FERC ¶ 61,181 at P 19 (2014); *MidAmerican Transco Cent. Cal. Transco, LLC*, 147 FERC ¶ 61,179 at P 34 (2014).

[32] Workpapers showing the derivation of the carrying charges are set forth in Exhibit No. ES-220.

[33] Similar changes are being made to the formula rate in ISO-NE OATT Schedule 1, Appendix A (NSTAR).

exhibits calculate the projected revenue requirements under each of the Transmission Service Formula Rates and under the ISO-NE OATT Schedule 1 Appendix A for the twelve-month period June 1, 2016 through May 31, 2017 (proposed one-year amortization) and for the thirty-six month period June 1, 2016 through May 31, 2019 (alternative three-year amortization) with and without the transmission merger-related costs. The exhibits also calculate the increase in transmission revenue requirements as a result of the inclusion of the transmission merger-related costs under both the one-year amortization and three-year amortization scenarios. The calculations show that under the Eversource Companies' proposed cost recovery mechanism (one-year amortization), the increase in transmission revenue requirements would be $37.8 million, whereas the increase under the alternative amortization scenario would be $49.1 million. *See* Testimony of Ms. Cooper, Exhibit No. ES-200 at Section VI.

VII. INFORMATION REQUIRED BY 18 C.F.R. § 35.13

Pursuant to the Commission's regulations, Eversource Service provides, to the extent not already provided elsewhere in this Transmittal Letter, the following information required by Section 35.13(b) and (c) of the Commission's rules:

- A description of the rate change and reasons for this filing are provided in Sections I, III, IV and V of this Transmittal Letter.
- None of the costs related to this filing have been alleged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory practices.
- Revenue impact statements showing the effect of Eversource Service's Proposed Cost Recovery Mechanism (one-year amortization) on the

Eversource Companies' transmission customers, as well as its Alternative Cost Recovery Mechanism (three-year amortization), are provided in Exhibits Nos. ES-214 through ES-219 and ES-221 through ES-226.

- As discussed further in Section VIII, Eversource Service seeks waiver of the cost of service statements required under Section 35.13(h) on the basis that these statements are not relevant to this application. As noted, Attachment F, Schedule 1, Schedule 21-NSTAR, and Schedule 21-ES to the ISO-NE Tariff contain formula rates and this filing does not affect formula rate components other than those specifically identified in the proposed revisions.

VIII. REQUEST FOR WAIVERS AND EFFECTIVE DATE

Eversource Service requests an effective date of June 1, 2016 for the tariff amendments incorporating cost recovery for transmission merger-related costs.

Eversource Service respectfully requests waiver of the requirement to submit full Period I and Period II cost-of-service statements under 18 C.F.R. § 35.13; this request is consistent with prior waivers granted by the Commission for formula rates. *See, e.g.*, *Nev. Power Co.*, 151 FERC ¶ 61,131at P 87 (2015); *PacifiCorp*, 147 FERC ¶ 61,227 at P 83 (2014); *PPL Elec. Utils. Corp*., 125 FERC ¶ 61,121 at PP 40-41 (2008); *Pub. Serv. Elec. & Gas Co*., 124 FERC ¶ 61,303 at P 23 (2008); *Commonwealth Edison Co*., 119 FERC ¶ 61,238 at P 94 (2007), *order on reh'g*, 122 FERC ¶ 61,037, *order on reh'g*, 124 FERC ¶ 61,231 (2008).

Furthermore, to the extent that any filing requirements of Part 35 of the Commission's regulations are not satisfied by this transmittal letter and the materials enclosed herewith, Eversource Service respectfully requests waiver of such requirements.

IX. PRIOR NOTIFICATIONS, POSTING AND CERTIFICATION OF SERVICE

Under the terms of the Transmission Operating Agreement between New England Participating Transmission Owners ("PTOs") and ISO-NE, PTOs must provide written notification to ISO-NE and New England stakeholders at least thirty days in advance of a Commission filing that contains revisions to rates or charges for transmission services under the ISO-NE OATT. Eversource provided such notice on October 30, 2015, which was sent by e-mail on that date to ISO-NE; all members of the New England stakeholder body, the NEPOOL Participants Committee; as well as its subcommittee, the NEPOOL Transmission Committee; and the Executive Director of the New England Conference of Public Utilities Commissioners. The notice was also posted to the ISO-NE website.[34] In addition, Eversource was on the agenda for the November 12, 2015 NEPOOL Transmission Committee, and the November 18, 2018 PTO Administrative Committee, at which meetings a representative of Eversource presented information on this proposed filing and was available for questions.

Pursuant to Section 35.2(d) of the Commission's Regulations, a copy of this filing is being served on representatives of the six state commissions in New England. It is also available for public inspection, during regular business hours, in a convenient form and place, at the offices of Eversource. Additionally, through the auspices of ISO-NE, which

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[34] Eversource's notice can be found on the ISO-NE website at http://iso-ne.com/committees/transmission/transmission-committee under "Eversource October 30 Notice of Tariff Revisions" posted November 5, 2015.

is the transmission provider under the ISO-NE Tariff, this filing is being posted on ISO-NE's website, www.iso-ne.com. Eversource Service requests waiver of the requirement to post by mailing paper copies to customers under the ISO-NE Tariff. Waiver of paper service is consistent with the Commission's decision to establish electronic service as the default method of service lists maintained by the Commission Secretary for Commission proceedings. *Electronic Notification of Commission Issuances*, Order No. 653, FERC Stats. & Regs. ¶ 31,176 (2005). This filing will be posted to the FERC filings section of the ISO-NE internet site; this is consistent with Eversource and other New England transmission owners' requests for similar waiver of paper service with regard to filings associated with the ISO-NE OATT.

X. REQUEST FOR CONFIDENTIAL TREATMENT

Eversource Service requests confidential treatment for certain information related to Eversource's vendors and employees. Vendor-specific pricing information is competitively sensitive, and disclosure of this information could cause business injury both to Eversource and to the vendors with which it contracted. Vendor-specific negotiations and pricing ordinarily are not made public, and public disclosure of such information could expose Eversource's and/or its vendors' pricing positions to competitors and could cause business injury both to Eversource and its vendors. For example, if vendors cannot maintain confidentiality for their pricing decisions, such vendors could be dissuaded from providing discounts to certain utilities – an outcome that could harm customers. To prevent disclosure of amounts that specific vendors charged, Eversource is retaining in the public version the amounts such vendors charged but redacting vendor names and other identifying information associated with such amounts.

Eversource is also redacting employee-specific information. Employee-specific information is confidential and sensitive information that may be covered by confidentiality arrangements; the disclosure of certain information (e.g., employee salaries and names) could violate confidentiality arrangements and unnecessarily allow for personal information regarding employees to be disclosed to the public. It is also competitively sensitive information for both Eversource and its employees as it reveals Eversource's compensation structure. Pursuant to Order No. 769 and the Commission's regulations regarding privileged materials thereunder,[35] Eversource Service provides the information to the Commission in Exhibit Nos. ES-100, ES-105 to ES-109, ES-111 to ES-112, ES-200, ES-202 to ES-208, and ES-210 to ES-213 hereto, has marked those exhibits as confidential, and has filed a public version of this application with redacted Exhibit Nos. ES-100, ES-105 to ES-109, ES-111 to ES-112, ES-200, ES-202 to ES-208, and ES-210 to ES-213. Eversource Service also includes with this filing as Appendix E a proposed protective agreement, which individuals involved in this proceeding may sign and thereby gain access to the privileged materials.

[35] *Filing of Privileged Materials and Answers to Motions*, Order No. 769, 141 FERC ¶ 61,049 (2012); *see also* 18 C.F.R. § 388.112 (2015).

XI. COMMUNICATIONS AND SERVICE

Eversource Service requests that all communications regarding this filing be directed to the following individuals and that their names be entered on the official service list maintained by the Secretary for this proceeding:

Phyllis E. Lemell
Assistant General Counsel
Eversource Energy Service Company
P.O. Box 270
Hartford, CT 06141-0270
(860) 665-5118
(860) 665-5504 (fax)
phyllis.lemell@eversource.com

Christine Vaughan
Vice President, Rates and Regulatory
Eversource Energy Service Company
1 NSTAR Way
Westwood, MA 02090
(781) 441-8622
christine.vaughan@eversource.com

Lisa M. Cooper
Director, Transmission Rates &
Revenue Requirements
Eversource Energy Service Company
P.O. Box 270
Hartford, CT 06141-0270
(860) 665-2453
(860) 665-2805 (fax)
lisa.cooper@eversource.com

David B. Raskin
Gary A. Morgans
Heather M. Horne
Shaun Boedicker
STEPTOE & JOHNSON LLP
1330 Connecticut Avenue, NW
Washington, DC 20036
(202) 429-3000
(202) 429-3902 (fax)
draskin@steptoe.com
gmorgans@steptoe.com
hhorne@steptoe.com
sboedicker@steptoe.com

XII. CONCLUSION

For the reasons set forth above, Eversource Service respectfully requests that the Commission accept Eversource Service's request for recovery of transmission merger-related costs. Eversource Service further requests that the Commission implement the proposed changes by June 1, 2016.

Respectfully submitted,
/s/
David B. Raskin
Gary A. Morgans
Heather M. Horne
Shaun Boedicker
STEPTOE & JOHNSON LLP
1330 Connecticut Avenue, N.W.
Washington, DC 20036

Attachments

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in these proceedings.

Dated at Washington, DC this 26th day of February, 2016.

/s/ Kevin Haggerty
Kevin Haggerty
Steptoe & Johnson LLP
1330 Connecticut Avenue, NW
Washington, DC 20036
(202) 429-6745
khaggerty@steptoe.com

Exhibit No. ES-100

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Eversource Energy Service Company	)	**Docket No.**	**ER16-___-000**
Northeast Utilities Service Company	)	**Docket No.**	**ER03-1247-000**
ISO New England Inc. , *et al.*	)	**Docket Nos.**	**RT04-2-000**
	)		**ER04-116-000**
Bangor Hydro-Electric Company, *et al.*	)	**Docket No.**	**ER04-157-000**
NSTAR Electric Company	)	**Docket No.**	**EC06-126-000**
NSTAR Electric Company	)	**Docket No.**	**EL07-71-000**
NSTAR Electric Company	)	**Docket No.**	**ER07-549-000**
NSTAR, *et al.* and Northeast Utilities, *et al.*	)	**Docket No.**	**EC11-35-000**

PREPARED DIRECT TESTIMONY OF

CHRISTINE L. VAUGHAN

ON BEHALF OF EVERSOURCE ENERGY SERVICE COMPANY

EXHIBITS TO DIRECT TESTIMONY OF
CHRISTINE L. VAUGHAN

Exhibit No.	**Description**
ES-101	2013 Merger Integration Annual Interim Report (CT PURA Docket 14-05-06)
ES-102	2013 Merger Integration Annual Interim Report (MA DPU Docket 10-170)
ES-103	2015 Merger Integration Report
ES-104	Total Merger Savings Summary
ES-105	Calculation of Corporate and Administrative Labor Savings
ES-106	Calculation of Information Systems Savings
ES-107	Calculation of Insurance Savings
ES-108	Calculation of Professional Services Savings
ES-109	Calculation of Contract Services Savings
ES-110	Calculation of External Directors/Trustees Fees Savings
ES-111	Calculation of Materials & Supply Procurement Savings
ES-112	Calculation of Administrative and General Overhead Savings
ES-113	Calculation of Association Dues Savings
ES-114	Calculation of Shareholder Services Savings
ES-115	Inflation Rate Support (GDP)
ES-116	Allocation Percentage Support
ES-117	Cost of Debt Decline
ES-118	Non-Fuel Electric O&M Analysis
ES-119	Transmission O&M Per Dollar of Net Transmission Plant
ES-120	Cumulative Transmission Merger-Related Savings From 2012-2022
ES-121	Excerpt of Sage Management Consultants, LLC 2015 Management Audit of CL&P

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UNITED STATES OF AMERICA
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NSTAR Electric Company	)	**Docket No.**	**ER07-549-000**
NSTAR, *et al.* and Northeast Utilities, *et al.*	)	**Docket No.**	**EC11-35-000**

PREPARED DIRECT TESTIMONY OF
CHRISTINE L. VAUGHAN
ON BEHALF OF EVERSOURCE ENERGY SERVICE COMPANY

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A1. My name is Christine L. Vaughan. My business address is 1 NSTAR Way, Westwood, MA 02090.

Q2. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A2. I am employed by Eversource Energy Service Company ("Eversource Service") as the Vice President of Rates & Regulatory Requirements.

Eversource Service is a service company subsidiary of Eversource Energy[1] that provides centralized corporate, financial, accounting, legal, information systems and other services to its utility subsidiaries.

Q3. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND.

A3. I graduated from McGill University in Montreal, Canada in 1990 with a Bachelor of Engineering Degree and from Yale University in New Haven, CT in 1998 with a Master's in Business Administration. Additionally, I have earned the right to use the Chartered Financial Analyst designation.

Q4. PLEASE DESCRIBE YOUR BUSINESS EXPERIENCE.

A4. In April 2012 I became Vice President of Rates & Regulatory Requirements at Eversource Energy. Prior to my current position, I was employed by then-NSTAR Electric & Gas Corporation ("NSTAR E&G"). Between March 2007 and April 2012 I was the Director of Revenue Requirements of NSTAR E&G. From 2004, I was the Manager of Regulatory Requirements, performing services for the regulated affiliates of NSTAR,[2] including responsibility for regulatory filings concerning the financial requirements of these companies. Prior to my position at NSTAR, I worked as a management

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[1] "Eversource Energy" or "Eversource" refer to the current merged company and all of its operating utility subsidiaries (The Connecticut Light and Power Company ("CL&P"), Public Service Company of New Hampshire ("PSNH"), Western Massachusetts Electric Company ("WMECO"), Yankee Gas Services Company ("Yankee Gas"), NSTAR Electric Company ("NSTAR Electric") and NSTAR Gas Company ("NSTAR Gas")).

[2] "NSTAR" refers to the pre-merger holding company.

consultant for five years at Arthur D. Little and at Charles River Associates, a company who purchased a portion of Arthur D. Little. In this capacity, I assisted clients with financial issues such as acquisition support and asset privatization. I also helped clients develop long-range strategic plans and assisted them with market analysis. Prior to my consulting experience and my MBA, I worked for six years at DuPont and BASF as a development engineer.

Q5. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A5. The purpose of my testimony is to describe the benefits associated with the 2012 merger between Northeast Utilities[3] and NSTAR, two previously separate public utility holding company systems in New England. I will show that the merger produced substantial benefits for customers in several areas, and, in particular, that the merged companies have already achieved cost reductions that outweigh Eversource's merger-related costs. This is true both on an enterprise-wide basis as well as on a transmission-only basis. As a result, the Eversource Companies[4] are entitled to recover the transmission-related portion of their merger-related costs through their transmission rates.

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[3] "Northeast Utilities" refers to the pre-merger holding company.

[4] The "Eversource Companies" refers to NSTAR Electric, CL&P, WMECO and PSNH.

Q6. ARE YOU SPONSORING ANY EXHIBITS?

A6. Yes. I am sponsoring Exhibit Nos. ES-101 through ES-121. These exhibits provide support for the merger-related savings I discuss in my testimony.

Q7. ARE ANY OTHER WITNESSES PROVIDING TESTIMONY IN THIS PROCEEDING?

A7. Yes. While I describe the majority of the merger-related cost reductions, Mr. Michael Synan describes the changes that occurred to various benefits administration programs following the merger and the savings that resulted from these changes. These savings calculations depend in part on actuarial calculations, and Mr. Synan, as Director of Benefits Strategy at Eversource Service, is particularly well-qualified to address this subject.

In addition, Ms. Lisa Cooper, Director of Transmission Rates and Revenue Requirements, describes the costs that Eversource incurred in connection with the merger, the transmission tariff revisions and cost recovery mechanism that the Eversource Companies are proposing in this proceeding in order to recover their transmission merger-related costs, and the calculation of the revenue impact of the Eversource Companies' proposal.

I rely on both Mr. Synan's and Ms. Cooper's testimony to show that the transmission-related portion of the costs that the Eversource Companies incurred to achieve the merger are far outweighed by the transmission-related merger savings.

Q8. HOW IS YOUR TESTIMONY ORGANIZED?

A8. I begin my testimony by providing background information about Northeast Utilities and NSTAR, and explaining why they decided to merge. While this explanation was central to those companies' merger application, it is also helpful at this stage in order to put into perspective how Eversource was able to achieve the merger synergies that it accomplished. Following this introduction, I discuss the many benefits that the merger achieved. While cost reductions that flow through to customers are a significant element of these benefits, as have been recognized by Eversource's state regulators in Connecticut and Massachusetts, they are by no means the only ones. I then discuss in greater detail merger-related cost reductions (also referred to as savings) that Eversource achieved. Finally, relying on Mr. Synan's and Ms. Cooper's testimony, I show that the transmission merger-related savings have already outweighed the transmission merger-related costs. It is my understanding that this is the standard that the Commission uses in determining whether transmission merger-related costs may be included in rates. Inclusion of the costs of achieving the merger that are offset by merger benefits are a way of recognizing that the utility must incur costs to consummate the merger and achieve significant synergies, and that customers would not be receiving any merger-related savings in the absence of these investments by the merging entities.

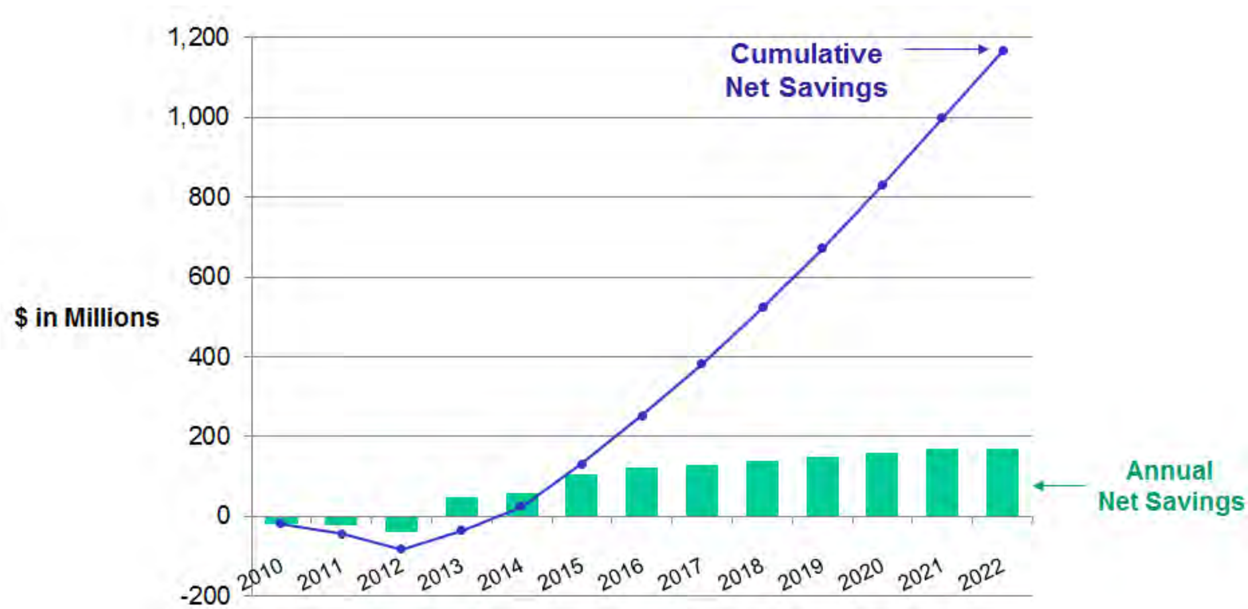
Q9. CAN YOU BRIEFLY SUMMARIZE YOUR CONCLUSIONS REGARDING MERGER-RELATED COSTS AND BENEFITS?

A9. Yes. Ms. Cooper testifies that as of September 30, 2015,[5] total Eversource enterprise-wide merger-related costs were $124.4 million, of which $37.4 million were transmission-related. Including the merger savings that Mr. Synan describes in his testimony, total enterprise-wide merger-related savings as of September 30, 2015 were $239.3 million, of which $58.7 million were transmission-related. *See* Exhibit No. ES-104. Thus, merger-related savings have already exceeded merger-related costs by a substantial margin on both a transmission-only and enterprise-wide basis.

Looking to the future, merger-related savings are expected to continue to grow, while merger-related costs beyond September 30, 2015 should be relatively small. As shown in the chart below, Eversource expects that by 2022, or ten years following the merger, cumulative enterprise-wide merger savings will have grown to approximately $1 billion, or about eight times

[5] A September 30, 2015 cut-off date for the merger-related costs and savings was originally selected in order to provide the Commission with the most current data while allowing for sufficient time to facilitate the preparation of this filing. On December 9, 2015, the Connecticut Public Utility Regulatory Authority ("CT PURA") re-opened its Docket No. 12-01-07RE01 for the limited purpose of reviewing CL&P's transaction and integration costs resulting from the NU and NSTAR merger, and to determine whether the proposed FERC filing is consistent with or in conflict with the Settlement Agreement previously approved by CT PURA. As a result, Eversource placed the instant filing on hold.

Eversource's merger-related costs. *See* Exhibit No. ES-103 at 4. This amounts to $279 million specifically for transmission customers over this same time period.[6] *See* Exhibit No. ES-120.



II. BACKGROUND

Q10. PLEASE IDENTIFY THE PARTIES TO THE MERGER TRANSACTION.

A10. The merger represents the combination of two public utility holding companies, Northeast Utilities and NSTAR. NSTAR was engaged primarily in the energy delivery business through its two wholly-owned utility

[6] The Merger Integration Report shows estimated savings through March 2022. For illustrative purposes only, the savings shown for 2022 in the above chart are annualized based on the estimated savings shown in the Merger Integration Report for the first three months of the year.

subsidiaries in Massachusetts, which were NSTAR Electric and NSTAR Gas. I will refer to NSTAR Electric prior to the merger as "Legacy NSTAR Electric," while "Legacy NSTAR" refers to NSTAR and all of its subsidiaries prior to the merger. Northeast Utilities was primarily engaged in the energy delivery business through its three wholly-owned electric subsidiaries CL&P, PSNH, and WMECO, and its wholly-owned gas distribution utility subsidiary Yankee Gas. I will refer to CL&P, PSNH and WMECO prior to the merger as the "Legacy NU Companies," while "Legacy NU" refers to Northeast Utilities and all of its subsidiaries prior to the merger. I collectively refer to the Legacy NU Companies and Legacy NSTAR Electric as the "Legacy Companies." The merger resulted in the combination of NU and NSTAR, with the new company since renamed Eversource Energy.

Q11. WHY DID NORTHEAST UTILITIES AND NSTAR DECIDE TO MERGE?

A11. Briefly, the merger arose as a result of the challenges facing all electric and gas utilities in the then-current environment – challenges that remain today. As has always been the case, utilities must provide a high quality of service, at a reasonable cost, and with the extraordinary level of reliability demanded by the critical importance of electricity and gas to the economy, public safety, and national security. Today, utilities also face the additional challenges of supporting substantially increased reliance on renewable energy while attempting to minimize price increases to customers. In addition, utilities are confronting the challenges of aging infrastructure. Meeting these challenges is necessary to assure that the utility is technologically positioned to provide the most efficient and effective metering, billing and customer care opportunities for customers and to maintain a committed, qualified workforce able to meet the demands of our digital society.

Although Legacy Northeast Utilities and Legacy NSTAR were each capable of addressing these issues on their own, they were able to do so more effectively and efficiently by merging into one holding company system with common interests and goals. Eversource is significantly larger than Legacy Northeast Utilities or Legacy NSTAR standing alone, and thus able to not only support needed future investment but also withstand volatility in the regional and national economy. The expanded service territory of the combined company brought about significant geographical diversity, enabling enhanced mutual support during storms or other service disruptions that are localized in nature. Eversource brought together the complementary strengths of a best in class distribution company (Legacy NSTAR) that was largely urban in nature and had significant expertise with underground systems, with a best in class transmission provider (Legacy NU) whose service territory was largely suburban and rural. Combining the two companies also provided the inherent benefits of bringing together two creative and capable workforces focused on identifying and implementing best practices.

Q12. DID EVERSOURCE ANTICIPATE THAT THE MERGER WOULD REDUCE COSTS?

A12. Yes – and as discussed below, those expectations were realized. Eversource determined that there would be substantial benefits of increased scale and scope as a result of the merger. Eversource anticipated cost savings associated with increasing operating efficiencies, the implementation of best practices and process improvements, increased purchasing leverage, and the elimination of duplicative positions – the benefits of which would be passed on to the Eversource Companies and their customers. The increased scale of Eversource was expected to enhance investments in infrastructure, information systems and other items to be spread over a larger customer base, thereby lowering per customer costs. And the merger was expected to make possible investments in technology and processes that might be less feasible from an economic perspective for Legacy NU or Legacy NSTAR to undertake on a stand-alone basis.

These anticipated cost reductions were reflected in a projected Net Benefits Analysis that Legacy NU and Legacy NSTAR prepared prior to the merger (discussed below in Section IV.A). That analysis showed that net savings of $784 million was achievable in the first ten years following the merger. As discussed below, those projections have been borne out to date, and Eversource anticipates the net savings will exceed this level. Unlike the projections reflected in the Net Benefits Analysis, the net savings in this filing reflect actual costs and benefits, calculated through September 30, 2015.

III. MERGER BENEFITS

Q13. PLEASE DISCUSS THE OVERALL BENEFITS RESULTING FROM THE MERGER.

A13. One of the key benefits of the merger, and the primary subject of this testimony, is the reduction in costs that Eversource realized as a result of the merger. Focusing on the same cost categories that Eversource analyzed in the Net Benefits Analysis that the merging companies performed prior to the merger, Eversource calculated that, as of September 30, 2015, the merger has produced savings for transmission customers of $58.7 million, as compared to $37.4 million of transmission-related merger costs. I provide the details behind these calculations below (with Mr. Synan providing the details of the benefits administration calculations), while Ms. Cooper provides the details behind the merger costs.

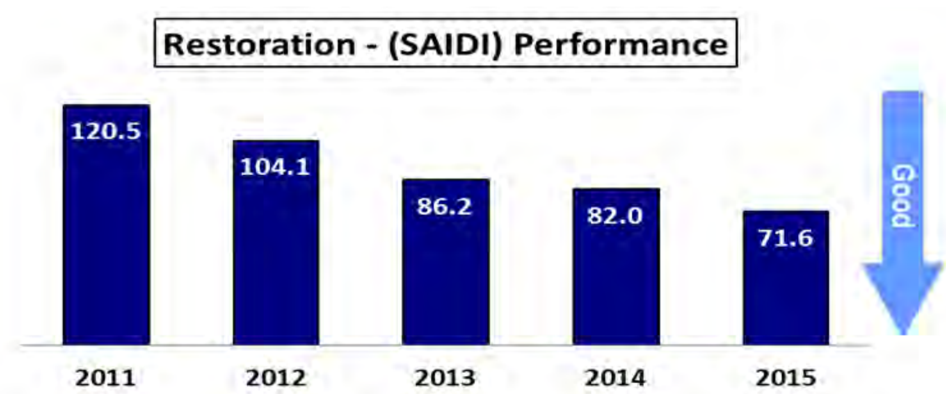
It is my understanding that the Commission does not take into account future projected savings in determining whether a utility may recover its transmission-related merger costs, and Eversource's calculations do not include any such savings. However, it is noteworthy that transmission merger-related savings continue to grow at about $20 million or more per year, whereas, as noted by Ms. Cooper, the Eversource Companies expect to incur very little transmission-related merger costs (less than $1.5 million going forward). As a result, the transmission-related net benefit from the merger, standing at $21.3 million through September 30, 2015, is expected to grow by at least this much every year. The merger is expected to produce well over $200 million in transmission net savings by 2022, ten years after the merger was consummated.

Almost all of these identified savings are in the Administrative and General expense area. As I discuss later in Section IV.C., during this same period, Eversource experienced substantial decreases in its Non-Fuel electric operation and maintenance ("O&M") expenses (in that section, I explain what I mean by the expression "Non-Fuel" electric O&M). From 2011 to 2014, these costs declined by approximately seven percent. The savings represent a combination of merger-related savings and good business practices. In addition, it is noteworthy that while Eversource was experiencing these substantial cost reductions, other electric utilities have faced rising Non-Fuel electric O&M costs over this same time period. Thus, it is fair to say that the merger had a significant role in achieving these cost reductions. A graph showing these cost reductions is included in Section IV.C.

The merger has produced many other benefits for Eversource's customers. The merger has strengthened Eversource's balance sheet, which has helped the Eversource Companies finance the substantial transmission system expansion that the Eversource Companies have been engaged in. Eversource Energy now holds a corporate credit rating of A from Standard and Poor's, and is the only utility holding company in the country with a rating that high. From 2012 to 2014, the Eversource Companies' debt costs declined from 5.06% to 4.69%, resulting in lower costs to consumers. *See* Exhibit No. ES-117.

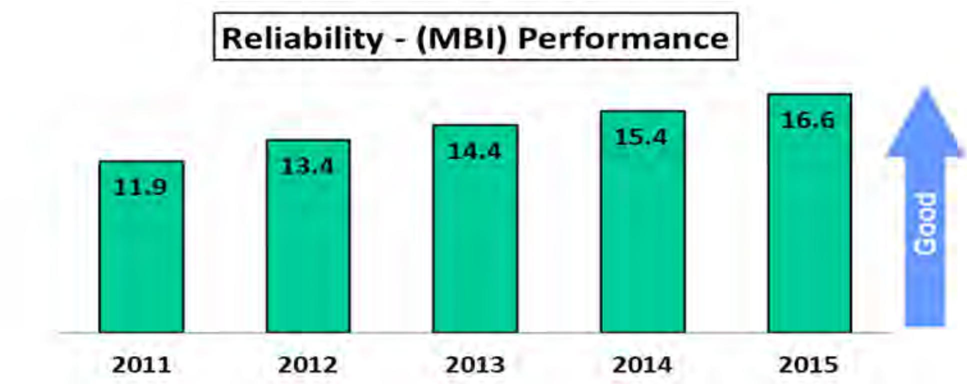
As anticipated, the expanded service territory of the Eversource Companies within a single holding company system has brought significant geographic diversity, enabling easier access to mutual support during storms and other service disruptions. All three states in which the Eversource Companies do business are prone to severe weather, so having the flexibility to move crews from one part of the Eversource Companies' service area to another can speed the restoration process. The weather in coastal Connecticut, for example, can be very different from that in Boston. While all utilities have mutual assistance arrangements for these events, it can be quicker and more cost effective for one Eversource Company to call upon one of its affiliates in such situations.

The benefits associated with Eversource's expanded size also include substantial, documented improvements in service reliability. For example, the chart below shows that between 2011 and 2015, the System Average Interruption Duration Index ("SAIDI") (which shows the average outage duration on Eversource's systems excluding outages caused by major storms) has declined by 41% on an enterprise-wide basis.[7]



[7] SAIDI information is available in Responsible Energy: Northeast Utilities 2014 Sustainability Report at p.29 (available at: https://www.eversource.com/Content/docs/default-source/pdfs/responsible-energy-2014.pdf?sfvrsn=2); Eversource 2015 Proxy Statement at p. 36 (available at: https://www.eversource.com/Content/docs/default-source/pdfs/2015-eversource-proxy.pdf).

In addition, the chart below shows that between 2011 and 2015, the average Months Between Interruptions ("MBI") has increased by 39% on an enterprise-wide basis.[8]



The speed with which service is restored in the event of an outage and the frequency of outages are key concerns of all utilities, and of course depends upon the nature of the outages experienced. But the geographic diversity and greater resources brought about by the merger have definitely helped in this area. Similarly, Eversource has increased its ability to resolve regional problems due to its larger scale, as evidenced by Eversource's recent announcement of a partnership in the Access Northeast gas pipeline

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[8] SAIDI and MBI information is contained in an Investor Call Presentation at p. 16, filed on February 4, 2016 with the Securities Exchange Commission by Eversource as part of its 8-K filing (available at: http://phx.corporate-ir.net/phoenix.zhtml?c=119413&p=irol-SECText&TEXT=aHR0cDovL2FwaS50ZW5rd2l6YXJkLmNvbS9maWxpbmcueG1sP2lwYWdlPTEwNzEyMzM5JkRTRVE9MCZTRVE9MCZTUURFU0M9U0VDVElPTl9FTlRJUkUmc3Vic2lkPTU3).

infrastructure project and continued commitment to the Northern Pass transmission project.

Q14. HAVE OTHER ENTITIES RECOGNIZED THESE MERGER BENEFITS?

A14. Yes. In both Connecticut and Massachusetts, retail regulators have reviewed Eversource's merger-related costs and benefits, and have determined that the benefits outweighed the costs. Because Eversource was able to make this showing, these regulatory agencies have allowed certain Eversource utilities to include merger-related costs in their retail rates.

Specifically, CT PURA approved CL&P's request to recover approximately $25 million of distribution merger-related costs (Docket No. 14-05-06). CT PURA found that the merger provided benefits to customers that exceeded the costs to achieve the merger, and approved a request to amortize the CL&P distribution portion of merger costs of approximately $25 million over a ten-year period. *Application of the Connecticut Light and Power Company to Amend Rate Schedules*, CT PURA Docket No. 14-05-06, Dec. 17, 2014 Final Order at 156. I have attached the 2013 Merger Integration Report submitted to the CT PURA demonstrating the merger-related savings and costs. Exhibit No. ES-101. Further, CT PURA recently reviewed relevant exhibits regarding the merger-related costs and savings information and concluded that the "[a]llocation for transmission merger-related costs was done correctly," and such costs are "legitimate A&G costs based on actual amounts for expense items under specific FERC accounts."[9]

In Massachusetts, the Massachusetts Department of Public Utilities ("MA DPU") approved NSTAR Gas's request to include approximately $5 million in gas merger-related costs in retail gas distribution rates. The MA DPU found that NSTAR Gas demonstrated that its merger-related savings exceed its merger-related costs, consistent with the 2013 Merger Integration Report submitted by the company. *Petition of NSTAR Gas Co.*, D.P.U. 14-150, October 30, 2015 Order at p. 132. These gas merger-related costs will be recovered over a ten-year period. I have attached the 2013 Merger Integration Report submitted to the MA DPU demonstrating the merger-related savings and costs. Exhibit No. ES-102.

In addition to these state agencies' recognition that merger-related savings exceed merger-related costs, an independent audit performed by Sage Management Consultants, LLC (authorized by the CT PURA) made multiple findings that the merger successfully integrated the functions of Legacy NU and Legacy NSTAR, created efficiencies, and achieved savings. *See* Exhibit No. ES-121, Sage Management Consultants, LLC 2015 Management Audit

[9] *Application for Approval of Holding Company Transaction Involving Northeast Utilities and NSTAR*, Docket No. 12-01-07RE01, Decision at 1, 8-9 (Feb. 19, 2016) (available at: http://www.dpuc.state.ct.us/FINALDEC.NSF/0d1e102026cb64d98525644800691cfe/d183b9f6a6e155a285257f61005d6a60/$FILE/120107RE01-021916.docx).

of CL&P ("Sage Audit"). For example, the Sage Audit found that the merger "offered the opportunity for a number of cost savings," pointing specifically to the significant savings achieved as a result of the consolidation of Legacy NU's and Legacy NSTAR's employee benefits program. Exhibit No. ES-121 at 188 (*see also* Synan Testimony, Exhibit No. ES-300, discussing the employee benefits savings in greater detail). The audit also noted ten-year projected net savings of $996 million enterprise-wide and found that "Eversource Energy has achieved the cost efficiencies promised by the merger, while also providing the best reliability results on record." Exhibit No. ES-121 at 41. Further, multiple other findings were made regarding the benefits of the merger, as well as the achievement of economies of scale and realization of cost efficiencies. *See, e.g., id.* at 5, 41 (noting that the "merger integration has gone well"); *id.* at 42 (providing illustrations of how "merger benefits have been achieved"); *id.* at 40 (noting the centralization of services following the merger which "enables the capture of economies of scale and the sharing of good practices across the operating companies"); *id.* at 43 (noting Eversource's work on reducing O&M costs while improving service); *id.* at 157 (noting improvements in financial ratings for CL&P and Eversource since the merger); *id.* at 165-66 (discussing the efficiencies and appropriate organization of the accounting and tax functions following the merger); *id.* at 297-98, 309-10 (noting Eversource's development of a "thorough" information technology merger integration roadmap and its successful execution).

Q15. YOU REFERRED TO A MERGER INTEGRATION REPORT IN YOUR PRIOR ANSWER. WHAT IS THE MERGER INTEGRATION REPORT?

A15. The Merger Integration Report is an analysis of the merger-related costs and savings achieved, and was submitted to both the CT PURA and MA DPU in support of CL&P's and NSTAR Gas's respective requests to include distribution merger-related costs in retail rates. The Merger Integration Reports submitted in the state proceedings used the same approach as the "Net Benefits Analysis" approved by the MA DPU and CT PURA when these state regulatory bodies initially reviewed the merger request. The Net Benefits Analysis applied the methodological approach of Thomas Flaherty, who is a recognized industry expert on business consolidation. Mr. Flaherty's framework is a well-accepted methodology for assessing the savings related to corporate mergers. Mr. Flaherty reviewed an earlier version of the Net Benefits Analysis (then based on projections) for the Northeast Utilities and NSTAR merger in the merger proceeding before the

MA DPU, and determined that the Net Benefits Analysis he reviewed provided a reasonable depiction of the potential for future savings.[10]

Q16. IS THE MERGER INTEGRATION REPORT PREPARED FOR THIS FILING BASED ON PROJECTIONS?

A16. Unlike the Net Benefits Analysis, which was based on pre-merger projections, the Merger Integration Report prepared for this filing is based on actual data for the historical period through September 30, 2015. Of course, for the period after September 30, 2015, the Merger Integration Report is based on projections.

Q17. HAVE YOU PROVIDED THIS MERGER INTEGRATION REPORT IN THIS PROCEEDING?

A17. Yes. Exhibit No. ES-103 includes an updated Merger Integration Report with data through September 30, 2015, which will be filed with the CT PURA as a compliance requirement of the CT PURA merger approval (Docket No. 12-01-07). The costs and savings set forth in my testimony build on the same support used in the Merger Integration Reports filed with the CT PURA and MA DPU to justify the distribution merger-related costs.

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[10] Rebuttal Testimony of Thomas J. Flaherty, Exh. JP-TJF-1 at 16, D.P.U. 10-170 (June 10, 2011) (available at: http://web1.env.state.ma.us/DPU/FileRoomAPI/api/Attachments/Get/?path=10-170%2f61311jptrbtr.pdf).

Q18. HOW IS THE MERGER INTEGRATION REPORT ORGANIZED?

A18. The Merger Integration Report contains a summary spreadsheet for each category of savings that shows the annual savings for that category. Depending upon the year in which the savings are determined, the Merger Integration Report escalates the savings for each year by an appropriate inflation rate in order to reflect the savings achieved. In addition, the savings in each cost area are divided between capital and non-capital (i.e., O&M expense) items based on the capitalization rate for that cost area. For capital items, an annual return and yearly depreciation are calculated, reflecting the capital cost savings for such items. The capital cost savings are added to the O&M expense to produce the total savings for that item. Finally, for each area, the total savings are compared to the projected savings shown in the Net Benefit Analysis.

IV. CALCULATION OF MERGER-RELATED COST REDUCTIONS

A. Introduction

Q19. EARLIER IN YOUR TESTIMONY YOU INDICATED THAT THE MERGER HAS PRODUCED $239.3 MILLION OF MERGER-RELATED SAVINGS ON AN ENTERPRISE-WIDE BASIS THROUGH SEPTEMBER 30, 2015. HOW DID EVERSOURCE MAKE THIS DETERMINATION?

A19. Before the merger was consummated, Eversource performed a Net Benefits Analysis that estimated the savings that Eversource would be able to achieve through the merger. The savings in that analysis were derived primarily on the basis of past experience with the merger that formed NSTAR. Thomas Flaherty performed an independent review of that analysis and determined that the nature and level of savings shown in the analysis provided a reasonable portrayal of the future savings that can be anticipated to occur if the merger proceeded as planned.[11] On June 9, 2014 in CT PURA Docket No. 14-05-06, following the consummation of the Northeast Utilities – NSTAR merger, Eversource prepared a 2013 Annual Interim Merger Integration Report that calculated the actual merger-related costs and benefits through December 31, 2013, and projected savings for the years 2014

[11] Rebuttal Testimony of Thomas J. Flaherty, Exh. JP-TJF-1 at 16, D.P.U. 10-170 (June 10, 2011).

through 2022. The Merger Integration Report provided actual savings by functional area consistent with the Net Benefits Analysis. In each functional area, the Merger Integration Report identified the principal steps taken to achieve merger-related savings. To quantify these merger-related savings, the Merger Integration Report tracked the savings attributable to merger-related integration activities in each functional area. The Merger Integration Report has been updated since that first interim report; the 2015 version now calculates cost savings through September 30, 2015 (see Exhibit No. ES-103). My testimony in this proceeding is based on this Merger Integration Report.

Q20. WHAT COST AREAS DID EVERSOURCE SERVICE EXAMINE IN DETERMINING THE AMOUNT OF MERGER-RELATED SAVINGS?

A20. Eversource analyzed merger-related savings in the following 11 categories: corporate and administrative labor; benefits administration; information systems; insurance; professional services; contract services; external directors/trustees fees; materials and supply procurement; administrative and general overhead; association dues; and shareholder services. All of these categories appeared in the original Net Benefits Analysis, and are reflected in the Merger Integration Report as well.

Q21. OVER WHAT PERIOD WERE THESE SAVINGS REALIZED?

A21. Merger-related savings began in 2012, immediately following the merger, and are continuing. Our calculation is current through September 30, 2015.

Q22. IN GENERAL, WHAT DO THESE SAVINGS REFLECT?

A22. These savings largely reflect cost-reduction or cost-avoidance opportunities through the consolidation of the stand-alone operations of two holding company systems into a single system. This integration of Legacy NU and Legacy NSTAR enabled elimination of duplicative functions and positions, combination of similar corporate activities, reductions in scope, and aggregation of external purchases of commodities and services.

Q23. ARE THE SAVINGS CALCULATED ON AN ACCOUNT BY ACCOUNT BASIS OR ON A FUNCTIONAL BASIS?

A23. The savings are calculated on a functional basis, because that is how Eversource operates. Each business unit and department within Eversource serves a different function that enables Eversource to obtain the applicable and necessary corporate services. Corporate activities and corporate budgets reflect these functional lines. Determining the savings achieved in performing these activities necessarily involves an assessment on a functional basis. While for accounting purposes Eversource's costs are recorded to specific accounts, Eversource organizes its activities, and thus best assesses its savings, along functional lines rather than based on specific accounts.

Q24. PLEASE PROVIDE A SUMMARY OF THE MERGER-RELATED SAVINGS.

A24. The following table provides a category-by-category breakdown of the savings through September 30, 2015:

Table: Merger-Related Savings[12]

Savings Category	Enterprise-Wide Savings ($ Millions)	Savings Allocated to Transmission ($ Millions)
Corporate and Administrative Labor	$ 122.0	$ 30.5
Benefits Administration[13]	$ 57.5	$ 14.4
Information Systems	$ 18.2	$ 4.5
Insurance	$ 7.5	$ 2.6
Professional Services	$ 4.3	$ 1.5
Contract Services	$ 13.0	$ 1.6
External Directors/Trustees Fees	$ 3.3	$ 1.2
Materials and Supply Procurement	$ 8.1	$ 1.0
Administrative and General Overhead	$ 2.1	$ 0.5
Association Dues	$ 1.1	$ 0.4
Shareholder Services	$ 2.1	$ 0.4
Total:	$ 239.3	$ 58.7

Q25. HOW WERE THESE SAVINGS CALCULATED?

A25. The savings calculations for each category are discussed in detail below. The merger-related savings were calculated in the same manner as in the Merger Integration Reports filed with the state regulatory commissions. The savings

[12] *See* Exhibit No. ES-104 for a detailed chart of total merger-related savings. Numbers in the above table may not match the totals due to rounding.

[13] Benefits Administration is discussed in Mr. Synan's testimony, Exhibit No. ES-300.

are determined in each year in which the cost reduction occurs, and then escalated by an appropriate inflation rate in order to reflect the savings achieved. For example, if Eversource determined that 100 positions were terminated in 2013 as a result of the merger, the cost savings associated with that reduction is calculated for 2013 based on 2013 wage levels. Cost savings of this nature continue into future years, so the 2013 savings are escalated by an inflation rate to calculate the 2014 savings in this area. Eversource used a general inflation rate (the Gross Domestic Product ("GDP") price deflator) for all cost categories except wages and health costs. Health costs have experienced higher than average inflation rates for many years, so a health cost inflation index was used; Eversource's historical merit wage increase rate was used for wages. In addition, the savings in each cost area are divided between capital and non-capital (i.e., O&M expense) items based on the capitalization rate for that cost area. This is necessary because the savings associated with capital items, just like capital costs, are realized over the life of the asset, not in the year in which the savings occur. For capital items, an annual return and yearly depreciation are calculated, reflecting the capital cost savings for such items. The capital cost savings are added to the O&M expense savings to produce the total savings for that item.

Q26. WHY ARE THE MERGER SAVINGS DIVIDED INTO THESE 11 CATEGORIES?

A26. Eversource reviewed the functional areas listed above based on the methodology used in the Merger Integration Reports (see Exhibit Nos. ES-101 through ES-103, discussed above).

Q27. HOW DO THE SAVINGS SHOWN IN THE MERGER INTEGRATION REPORTS COMPARE TO THOSE SHOWN IN THE NET BENEFITS ANALYSIS?

A27. As I discussed earlier in my testimony, the Net Benefits Analysis was a projection of merger cost savings, whereas the updated Merger Integration Report (Exhibit No. ES-103) calculates actual savings through September 30, 2015. For the period ending September 30, 2015, the savings shown in the Merger Integration Report were higher on an enterprise-wide basis than those shown in the Net Benefits Analysis. The Merger Integration Report shows a comparison between the Net Benefits Analysis's projections and the Merger Integration Report's calculation of actual savings through September 30, 2015 for each savings category.

B. Specific Cost Reduction Areas

1. Corporate & Administrative Labor

Q28. PLEASE DESCRIBE THE MERGER-RELATED CORPORATE AND ADMINISTRATIVE LABOR SAVINGS.

A28. Following the close of the merger, the corporate and administrative function of the newly merged entity, primarily in the service company, was evaluated and reorganized to eliminate redundant positions, leading to staffing reductions. These reductions were achieved through the reduction of employee positions ("merger-specific labor reductions") and through attrition ("merger-related attrition"). As demonstrated on Exhibit No. ES-105, as of September 30, 2015, merger-specific labor reductions and merger-related attrition accounted for the reduction of 383 positions (this amount does not include information systems-related merger-specific labor reductions or merger-related attritions associated with information systems restructuring, which are identified separately under the section "Information Systems" below). The 383 reductions occurred in the years 2012-2015 in the following business units: executive management, legal, operation shared services, external relations, finance accounting and planning, human resources, information systems, administrative and support, retail marketing & sales, customer care, and purchasing and materials management. In 2012, there were 200 merger-related departures (181 merger-specific labor reductions and 19 merger-related attritions); in 2013 there were 57 merger-related departures (41 merger-specific labor reductions and 16 merger-related attritions); in 2014 there were 77 merger-related departures (20 merger-specific labor reductions and 57 merger-related attritions); and in 2015 there were 49 merger-related departures (2 merger-specific labor reductions and 47 merger-related attritions). The staffing changes that resulted from the merger produced savings of $122 million, including employee-benefits costs and other indirect expenses associated with labor through September 30, 2015.

Q29. WHAT DO YOU MEAN BY MERGER-SPECIFIC LABOR REDUCTIONS?

A29. Merger-specific labor reductions are reductions arising from the elimination of duplicative and overlapping functions performed by the two pre-merger organizations. Eversource's Human Resource Department identified the reductions in personnel that resulted from the elimination of duplicative and overlapping corporate and administrative functions performed by Legacy NU and Legacy NSTAR. Merger-specific labor reductions do not include exits from Eversource for other reasons such as retirements, resignations, terminations for cause, deaths, probationary terminations, an exit from certain competitive businesses or reductions due to normal day-to-day business and resource needs.

Q30. HOW WERE THE SAVINGS RELATED TO MERGER-SPECIFIC LABOR REDUCTIONS CALCULATED?

A30. To measure the savings for merger-specific labor reductions, Eversource identified each position in the corporate and administrative function that was eliminated due to duplicative and overlapping functions (a total of 244 positions through September 30, 2015), and identified the corresponding salary for each position eliminated. In addition to an employee's salary, there are costs related to each employee's employment with Eversource – these added costs include payroll taxes, pension benefits/post-retirement benefits other than pension ("PBOP"), healthcare benefits, and incentive pay.[14] The inclusion of these items is essential in measuring the fully-loaded adjusted salary savings associated with a reduction in employment levels. This information is included on Exhibit No. ES-105. Because the annualized, adjusted salary savings for each merger-specific labor reduction continue to be realized by Eversource on a going forward basis, for the years following each reduction, Eversource applied a wage growth escalation factor to reflect the realized savings in each given year. The escalation wage growth factors are based on Eversource's historical merit wage increase (which is based on

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[14] The calculation applied a 10% incentive pay for all years, which is an average target incentive pay percentage for Eversource employees. In addition, the calculation applied the weighted loader percentages for payroll taxes, PBOPs, healthcare benefits. Exhibit ES-105 shows the loaders used.

current market rates, updated competitive market assessments, and overall compensation philosophy), and the same escalation wage growth assumptions were also used in the state proceedings discussed above.

Q31. WERE THERE COSTS ASSOCIATED WITH THESE REDUCTIONS?

A31. Yes. Eversource provided substantial monetary assistance to the employees who were affected by the separation program. About one-fourth of the total requested cost of the merger involved assistance to these employees. Eversource also provided separation assistance services to these employees to assist with career transition and outplacement. These costs, along with the separation program costs, are reflected in the merger-related cost analysis included in Ms. Cooper's testimony, Exhibit No. ES-200. Eversource's transition services provided extensive assistance to transitioning employees, including an outplacement program that offered one-on-one job search coaching with guidance on networking and interviewing, resume preparation, job lead identification, and online 24/7 job search guidance. Moreover, Eversource offered individualized post-retirement career counseling for employees that included resume writing and post-retirement coaching, as well as guidance on wellness and life balance. Since the merger in 2012, three quarters of transitioning employees took advantage of these programs.

Q32. WHAT DO YOU MEAN BY MERGER-RELATED ATTRITION?

A32. Merger-related attrition is the difference between the number of employee exits and the number of new hires for employees who performed shared services functions on a year-by-year basis.[15] Exhibit No. ES-105 demonstrates yearly exits and yearly hires for shared services employees of Eversource. Departing employees who performed shared services functions (functions that were integrated pursuant to the merger, including Finance, Human Resources, Legal, Customer Care/Customer Relations) and who were not replaced were considered merger-related attrition. Pre-merger, Legacy NU and Legacy NSTAR would have filled the positions that opened up due to employee attrition. With the merger, Eversource was able to provide additional resources to absorb the workload of the former employee, thereby eliminating the need for re-filling the position. For example, in 2012, Eversource had 56 attrition-related departures. However, Eversource only had 37 offsetting hires in 2012, resulting in a total of 19 attrition-related merger departures in 2012. Although Eversource experienced attrition-related departures in many areas, the savings calculation only includes attrition in the shared services functions.

[15] Shared service employees represent approximately 30% of the total workforce.

Q33. WHY IS THE INCLUSION OF COST SAVINGS ASSOCIATED WITH ATTRITION APPROPRIATE?

A33. Eversource's inclusion of attrition in the merger savings is appropriate because, in the absence of the merger, Legacy NU and Legacy NSTAR would have filled the positions that opened up due to employee attrition. As I discussed above, with the merger, there is the opportunity to obtain savings through the elimination of redundant job positions. If a position is opened up due to employee attrition, and the position can be eliminated rather than re-filled because other resources now exist within the combined company, then the cost savings associated with eliminating that position are a direct result of the merger. In other words, the elimination of the position (and the resulting cost savings) would not occur but for the completion of the merger and the integration of two stand-alone companies. Therefore, attrition is a critical tool for achieving merger-related savings while mitigating the impact for employees who may want to remain with the new, combined entity.

Q34. HOW WERE THE SAVINGS RELATED TO MERGER-RELATED ATTRITION CALCULATED?

A34. To measure the savings for merger-related attrition, Eversource calculated an average yearly salary for attrition-related departures, then multiplied that salary by the number of attrition-related departures for a given year. The average yearly salary for 2012 and 2013 was based on the average salary for shared services employees of Legacy NU and Legacy NSTAR. The average yearly salary for 2014 and 2015 was based on the average salary of offsetting hires. Consistent with merger-specific labor reductions, there are associated costs related to each employee's salary including payroll taxes, PBOPs, healthcare benefits, and incentive pay. The inclusion of these items is essential in measuring the fully-loaded adjusted salary savings. Eversource then divided the resulting sum in half (in order to take into account that attrition-related departures did not always occur at the beginning of the year) to arrive at the average attrition savings for a given year.[16] Eversource applied the same escalation factors to merger-related attrition as were applied to merger-specific labor reductions. As shown in Exhibit No. ES-105, as of September 30, 2015, a total of 139 positions were eliminated due to merger-related attrition.

[16] When salary savings are escalated for future years, the entire yearly salary is taken into account. For example, in 2012, the average salary was multiplied by the number of attrition-related departures (19), then divided in half to arrive at the savings for 2012. However, given that those 19 attrition-related departures persisted through subsequent years, the fully loaded annual salary for those 19 departures was applied to escalate the savings for 2013-2015.

Q35. PLEASE EXPLAIN HOW YOU CONFIRMED THAT THE MERGER-SPECIFIC LABOR REDUCTIONS AND MERGER-RELATED ATTRITION WERE IN FACT DUE TO THE MERGER.

A35. As discussed above, merger-specific labor reductions are known to be merger-related because they were specifically identified as redundancies due to the integration of Eversource's functions in the corporate and administrative area, which were primarily in the service company. By limiting the savings due to net attrition to areas targeted and most affected by the merger, the corporate function, this provides a reasonable quantification of the labor savings achieved due to the merger. Net attrition took into account the differences between terminations and hires by examining integrated functions that were affected by the merger.

As shown in Exhibit No. ES-105, the staffing changes that resulted from the merger produced enterprise-wide savings of $122 million, including employee-benefits costs and other indirect expenses associated with labor. Using the allocation factor for labor described below, total transmission merger-related savings within the labor category are $30.5 million.

2. Benefits Administration

Q36. WHAT ARE THE BENEFITS ADMINISTRATION SAVINGS?

A36. Benefits administration cost reduction calculations are discussed in Mr. Synan's testimony, Exhibit No. ES-300. As shown in his testimony, benefits administration changes produced enterprise-wide savings of $57.5 million and total transmission merger-related savings of $14.4 million.

3. Information Systems

Q37. PLEASE PROVIDE A DESCRIPTION OF THE INFORMATION SYSTEMS CHANGES THAT RESULTED FROM THE MERGER AND THE ASSOCIATED SAVINGS.

A37. As part of the merger integration effort, Eversource conducted a comprehensive assessment of its Information Technology ("IT") structures. Due to the merger, Eversource combined two separate IT departments (including two IT labor forces, two separate technology platforms, and differing principles and processes) into one functional department with applications that function across all of Eversource's departments and businesses. Through this effort, the new IT organization implemented efficiencies and best practices to support the entire post-merger organization, including the Eversource Companies. The identification of best practices by a single company on a stand-alone basis provides fewer opportunities for cost savings as compared to a similar process within a merged organization. Identifying best practices within the context of a merger allows for comparisons of practices under common ownership, and enables the companies to implement broader measures to implement practices that reflect complementary strengths, business strategies and management experiences of the two companies. The merger of Northeast Utilities and NSTAR enabled Eversource to identify and evaluate the differences in the way that the two organizations performed the IT function, and the recognition of those differences enabled Eversource to find a better way of doing business through the adoption of the new model.

In addition, this consolidation of services through this new IT support model enabled Eversource to eliminate other duplicate costs (e.g., software support and computer maintenance), and provided an integrated and centralized approach to IT services. Through the merger, Eversource realized the benefits of developing applications on a common platform rather than Legacy NU and Legacy NSTAR developing separate platforms.

To realize the need to "become one IT" after the merger, to maintain a secure and reliable technology environment, to implement innovative solutions that support changing business needs, and to better position Eversource for future needs, Eversource requested and evaluated bid proposals from multiple IT service providers. Eversource then restructured the IT department by contracting with two consulting companies, Infosys and Tata Consultancy Services ("TCS"), to provide the majority of IT functions to the newly merged entity. *See also* Sage Audit, Exhibit No. ES-121 at 297-98, 309-10 (discussing the IT restructuring and Eversource's development and successful execution of a thorough IT merger integration plan). The restructuring contemplated that Infosys and TCS would provide day-to-day "service the business" work, while the in-house IT team would focus on management, oversight, and strategic "change the business" work. This restructuring led to IT merger-specific labor reductions of 166 positions and merger-related attritions of 17 positions for a total of 183 positions in 2014 and 2015. The announcement of the restructuring in IT prompted some employees to leave the company to look for other jobs and as a result the organization experienced a level of attrition that has been included in the savings similar to that discussed above in the corporate and administrative labor savings category. Contracting with Infosys and TCS to perform IT services also allowed for the elimination of prior IT services contracts, thus resulting in efficiencies by eliminating duplicative contracts and applications. As demonstrated in Exhibit No. ES-106, the IT reorganization resulted in total savings of $18.2 million.

Q38. HOW WERE IT SAVINGS MEASURED?

A38. To measure IT-related savings, Eversource compared the pre-merger baseline contractor costs prior to restructuring with the new contractor costs. This comparison involved a calculation of the eliminated costs, and a comparison of those eliminated costs to the new charges of Infosys and TCS. More than offsetting the new charges of Infosys and TCS was the reduction to the internal IT labor force and other IT savings (system maintenance fee savings and system consolidation). The eliminated IT-specific labor costs were calculated in the same manner as merger-specific labor reductions (*see* Section IV.B.1., above). *See* Exhibit No. ES-106. Using the allocation factor for IT described below, total transmission merger-related savings within the IT category are $4.5 million.

4. Insurance

Q39. HOW WAS EVERSOURCE ABLE TO GENERATE INSURANCE SAVINGS AS A RESULT OF THE MERGER?

A39. Eversource, like other utilities and large corporations, utilizes a wide number of insurance policies to protect itself from potential liability and operating risks. Eversource utilizes insurance for automotive liability, director and officer liability, general liability, cyber risk liability, and professional liability, among other forms of potential liability. These contracts are necessary to help to ensure that Eversource is not exposed to excess risk for any of its operations. Following the merger, Eversource reviewed existing insurance policies held by both Legacy NU and Legacy NSTAR, and combined the individual Legacy NU and Legacy NSTAR policies as they expired. This led to savings in the newly negotiated contracts for two primary reasons: first, the increased size of the newly merged entity allowed Eversource to gain greater leverage in negotiating pricing for each of the new contracts. Second, as the newly merged entity was significantly larger with a more robust loss experience base, Eversource was able to reassess needed coverage levels and deductibles based on the new risk profile of the combined company and modify policies accordingly.

Q40. PLEASE EXPLAIN HOW YOU CALCULATED INSURANCE SAVINGS.

A40. To calculate these savings, Eversource compared the expiring annual premiums for both Legacy NU and Legacy NSTAR against the post-merger premiums for Eversource. Exhibit No. ES-107 shows this comparison for each of the various types of insurance policies utilized by Eversource. As shown in the exhibit, the total annual expense for the expiring Legacy NU and Legacy NSTAR premiums was $20.8 million. In total, Eversource saved approximately $2.2 million on an annualized basis. Its 2012 savings were $1.5 million as a result of premiums expiring throughout the year and its 2013 savings (the first full year the merger was in effect) were $2.2 million.

The savings Eversource realized with respect to its insurance contracts established a new baseline for insurance costs on a going forward basis. To recognize this, Eversource applied a GDP inflationary factor to 2013 annualized savings to calculate its 2014 annual savings, which were $2.2 million. Eversource then applied the 2015 GDP inflationary factor to 2014 savings to calculate insurance savings for the 2015 period covered by this filing, with customers realizing $1.7 million savings in 2015. Given these values, Eversource realized $7.5 million in total savings within the insurance category. Using the allocation factor for insurance described below, total transmission savings within the insurance category are $2.6 million.

5. Professional Services

Q41. PLEASE EXPLAIN THE PROFESSIONAL SERVICES SAVINGS THAT RESULTED FROM THE MERGER.

A41. Following the merger, Eversource worked to consolidate and reduce professional services activities (including corporate procurement credit cards, vendors for payroll services, vendors for staff management, external auditors, research services, call center contracts, and financial reporting services) through economies of scope, elimination of non-recurring duplicate services, and increased utilization of a broader skill base. In many cases these were duplicative functions in Legacy NU and Legacy NSTAR.

Q42. PLEASE EXPLAIN HOW YOU EXAMINED AND CALCULATED PROFESSIONAL SERVICES SAVINGS.

A42. To measure professional services savings, Eversource identified a number of services that were consolidated as a result of the merger, and calculated the savings that resulted from the consolidation by comparing pre-merger costs to post-merger costs. The primary savings area involved the consolidation of the companies' external auditors. Eversource terminated duplicative relationships with external auditors and only retained one external auditor, which resulted in savings. Legacy NU used [redacted] as its external auditor, while Legacy NSTAR used [redacted] as its external auditor. In 2012, Eversource retained only one contract, which was with [redacted] Eversource reviewed the total costs of each auditor's engagement prior to the merger and compared this amount to the cost of [redacted] engagement with the new larger merged company. Having one external auditor versus two resulted in initial savings of $770,000 annually.

Q43. DID EVERSOURCE REALIZE SAVINGS FOR ANY OTHER PROFESSIONAL SERVICES?

A43. Yes. Eversource also realized savings with respect to the following professional services:

- Staff Augmentation Contract Consolidation ([redacted]): This consolidated the management of staff augmentation into a single third party vendor to leverage volume and reduce administration and management fees. Eversource moved from [redacted] to [redacted] for payroll services.
- [redacted] service: Eversource integrated Legacy NSTAR's [redacted] service into the Legacy NU service at no additional cost.
- Elimination of [redacted] Lease: Due to the ability of Eversource to satisfy its office space needs in the Boston area through the use of Legacy NSTAR facilities, it was determined that

WMECO's lease with [redacted] was no longer needed. Eversource cancelled the lease effective August 31, 2012.

- Elimination of [redacted] NSTAR Fair Value Fees: Savings were derived by avoiding the duplicative engagement of [redacted] to calculate performance share compensation. [redacted] was performing the service for both Legacy NU and Legacy NSTAR under two separate contracts, so Eversource eliminated the Legacy NSTAR contract.
- Financial Reporting Integration: This effort involved insourcing XBRL/Edgarization 10-K filing requirements so that Eversource now completes this reporting process without external providers.
- P-Card/Travel & Expense Card consolidation: This consolidated the existing corporate procurement credit cards with a single vendor, resulting in increased volume rebates. The new corporate procurement cards were fully rolled out to Eversource's employees in the second half of 2013.

Because the initial savings realized by these consolidated services continued to accrue through September 30, 2015, Eversource applied a GDP inflationary factor to calculate ongoing savings. As shown in Exhibit No. ES-108, professional services savings totaled $4.3 million. Consistent with the allocation methodology discussed below, transmission-related savings total $1.5 million.

6. Contract Services

Q44. HOW WAS EVERSOURCE ABLE TO GENERATE SAVINGS IN THE CONTRACT SERVICES CATEGORY?

A44. Eversource, like most other large organizations, relies heavily on numerous outside vendors to help achieve its mission of providing safe and reliable electric energy to its customers. Legacy NU and Legacy NSTAR had numerous contract services from the same vendors and for similar functions. Following the merger, Eversource examined these common vendors of both Legacy NU and Legacy NSTAR and consolidated contracts where appropriate, frequently obtaining vendor concessions on certain contract provisions due to the merged entity's bargaining power. As a result of this examination, Eversource was able to consolidate and reduce contract service activities through elimination of non-recurring duplicate services and through enhanced economies of scale that the newly merged entity enjoyed relative to Legacy NU and Legacy NSTAR.

For many contract services, Eversource conducted a competitive bidding process that resulted in lower costs for the same contract service. The competitive bidding process involved both existing and new vendors, depending on the particular contract services that were bid. A few examples of contract services areas with cost savings are as follows:

- Contractor Staffing services were consolidated from many small vendors to a larger vendor that offered more value-added services;
- Office Products cost savings were achieved by competitive bidding with two existing vendors, resulting in the selection of one post-merger vendor; and
- Emergency Response Staging Site Service contracts that each Legacy company had separately were consolidated, resulting in more favorable pricing from the vendor.

Q45. HOW WERE CONTRACT SERVICES SAVINGS CALCULATED?

A45. To measure these savings, procurement agents responsible for vendor contracts consolidated or renegotiated existing contracts, tracking their vendor-specific cost savings ("cost savings").[17] Cost savings were determined on a contract-by-contract basis generally by comparing the pre-merger price and the renegotiated post-merger price (including rebates). If

[17] Cost savings were savings for existing products or services, where the final price per given unit was less than the current price paid by Eversource, including rebates given to Eversource. Eversource has not included "negotiated savings" – savings for new products or services where the final negotiated price was less than the initial offer price.

additional savings were realized in future years based on further negotiations, those increased savings would be recorded for future years as well. These savings assessments were recorded in 2012, 2013, and 2014, and in some instances resulted in multi-year savings for contracts that span multiple years. The savings realized, on a contract-specific basis, are shown in Exhibit No. ES-109. In total, Eversource realized (on an enterprise-wide basis) contract service savings of $1.8 million in 2012, $7.3 million in 2013, and $7.2 million in 2014. Each of these savings figures includes both O&M savings and capitalized savings. As shown in Exhibit No. ES-109, Eversource only included the O&M and the current expensed portion of savings included in capitalized accounts. As shown in Exhibit No. ES-109, Eversource achieved savings of $0.9 million in 2012, $3.8 million in 2013 and $4.4 million in 2014. Eversource applied a GDP inflationary factor to calculate savings realized by customers in 2015. This is appropriate here, as customers have realized savings to these contracts as in prior years, and Eversource still benefits from the same factors that led to realized savings in each of the three previous years.

Applying this inflation factor to Eversource's 2014 savings, and only examining the period of 2015 at issue in this proceeding, Eversource realized $3.9 million in savings to contract services in 2015 on an enterprise-wide basis. In sum, Eversource has realized $13 million in savings related to contract services. This amount represents total enterprise-wide savings; for transmission savings the Eversource Companies applied the applicable allocation factor described below for a total of $1.6 million in transmission savings.

7. External Directors/Trustee Fees

Q46. PLEASE EXPLAIN SAVINGS ATTRIBUTABLE TO EXTERNAL DIRECTORS/TRUSTEE FEES.

A46. Prior to the merger, Legacy NSTAR and Legacy NU each had separate boards of trustees ("Board"). The new combined Board structure reduced the number of trustees needed as compared to having two Boards and revised the compensation model.

Q47. HOW WERE SAVINGS CALCULATED?

A47. Savings were calculated by comparing the costs for the NU and NSTAR Boards of Trustees to the 2013 post-merger Board. That analysis showed that the pre-merger Boards had a total of 20 members and $4.0 million in annual compensation, as opposed to the consolidated 2013 merged board, which consisted of 13 members and total compensation of $2.9 million. *See* Exhibit No. ES-110. As stated previously, the new Board structure reduced the number of trustees and revised the compensation model. The reduced compensation of $2.9 million in 2013 included cash and stock awards. As shown in Exhibit No. ES-110, the reduction efforts resulted in total savings of

$0.2 million for 2012 and $1.1 million in 2013 (the first full year of the new Board). Because these savings continue to accrue with the merged Board, a GDP inflationary factor was applied for the years 2014-2015. Exhibit No. ES-110 demonstrates that total savings are $3.3 million. Consistent with the allocation methodology discussed below, transmission-related savings are $1.2 million.

8. Materials and Supply Procurement

Q48. HOW WAS EVERSOURCE ABLE TO GENERATE SAVINGS IN THE MATERIALS AND SUPPLY PROCUREMENT CATEGORY?

A48. Eversource, like most other large organizations, relies heavily on numerous outside vendors to provide the materials and supplies it requires to help it achieve its mission of delivering safe and reliable electric energy to its customers. Following the merger, Eversource consolidated the procurement contracts of Legacy NSTAR and Legacy NU by evaluating common vendors to both and renegotiating such contracts, realizing savings due to both consolidation of vendors as well as vendor concessions given to Eversource.

Purchases can be for specific projects or services, one-time events, or for multi-year needs and as a result, our cost savings can change year over year. Some vendors participate on multiple bids across categories, and therefore have multiple savings entries for different services. Major categories are put out to bid as contracts become due to expire, which influences year to year savings opportunities. Additionally, savings may be pro-rated for a year based on when the bids are awarded. A few examples of material and supply procurement efforts that generate cost savings are as follows:

- Savings resulting from a bid for material and supply procurement that spread savings over multiple years, and included rebates based on volumes. In addition, there were individual purchases for projects that were bid, where Eversource realized specific savings.
- A vendor whose savings varied over the three years from 2012 to 2014. In 2012, the vendor's contract included concessions for a partial year. In August of 2013, Eversource changed the transformers it purchased under the contract, so 2013 savings are prorated for a partial year, and 2014 includes a full year of savings.
- Eversource also reviewed the materials and supply procurement function across the enterprise, leading to over 100 duplicate items being eliminated and resulting in a lower ongoing material cost.

Q49. HOW DID EVERSOURCE CALCULATE THESE SAVINGS?

A49. To measure these savings, Eversource utilized the same methodology described in the contract services section above for 2012, 2013, and 2014. The savings realized, on a contract-specific basis, are included as Exhibit No. ES-111. In total, Eversource realized materials and supply procurement savings of $8.1 million for 2012-2015. Realized capitalized savings were calculated using the relevant capitalization rate and rate base return shown in Exhibit No. ES-111. As with contract services, Eversource applied a GDP inflationary factor to calculate savings realized by customers in 2015. For transmission savings Eversource applied the applicable allocation factor described below for a total of $1 million in transmission savings.

9. Administrative and General Overhead

Q50. WHAT ARE ADMINISTRATIVE AND GENERAL ("A&G") OVERHEAD COSTS AND HOW DID THEY CHANGE AS A RESULT OF THE MERGER?

A50. A&G overhead costs include office supplies, telephone expenses, employee business expenses and other miscellaneous costs. Following the merger, A&G overhead costs decreased as existing contracts were renegotiated or replaced due to Eversource's increased purchasing leverage, and as corporate personnel were reduced. Savings with any vendor can change year over year as a result of changing business models or changing vendors. For example, as shown in Exhibit No. ES-112, in 2013 Eversource consolidated the printing services used by Legacy NSTAR and Legacy NU, resulting in savings of $0.3 million in 2013. In 2014, Eversource experienced savings of $0.2 million from merger-related price concessions.

Q51. HOW DID EVERSOURCE CALCULATE THESE SAVINGS?

A51. To measure these savings, Eversource utilized the same methodology described in the contract services section above for 2013 through 2015. The savings realized, on a contract-specific basis, are included in Exhibit No. ES-112. As detailed in Exhibit No. ES-112, the total A&G savings amount was arrived at by calculating yearly total savings numbers for 2013 through 2015, including capitalized savings and yearly total O&M savings. Realized capitalized savings were calculated using the relevant capitalization rate and rate base return shown in Exhibit No. ES-112. Eversource applied a GDP inflationary factor to calculate savings realized by customers in 2015. This is appropriate here for the same reasons detailed in the contract services section above. In total, Eversource realized A&G overhead savings of $2.1 million for 2013 through 2015. Exhibit No. ES-112 demonstrates that the associated transmission savings (based on the applicable allocation factor described below) total $0.5 million.

10. Association Dues

Q52. HOW WAS EVERSOURCE ABLE TO GENERATE SAVINGS IN THE ASSOCIATION DUES CATEGORY?

A52. Eversource, like most other companies with utility subsidiaries, is a member of a number of various associations that helps it to fulfill its mission. Following the consummation of the merger, Eversource was able to reduce or eliminate certain dues, such as those for the Edison Electric Institute ("EEI") because there were duplicate dues from Legacy NU and Legacy NSTAR, or membership in certain associations was determined after further evaluation to be unnecessary post-merger. As part of this process, all voluntary professional memberships and corporate sponsorships/association fees were reviewed, evaluated, and some were determined not necessary and/or duplicative and were eliminated.

Q53. HOW DID EVERSOURCE CALCULATE THESE SAVINGS?

A53. To calculate these savings, Eversource compared the costs of association dues in 2012 and 2013 against those same costs prior to the merger. As shown in Exhibit No. ES-113, Eversource's savings in 2012 and 2013 totaled $0.5 million. To calculate savings in later years, Eversource applied a GDP inflationary factor in both 2014 and 2015 to the savings amount from 2013. This is reasonable as the factors underlying the decreased costs in 2013 were the same in both 2014 as 2015; namely, Eversource no longer has to pay two separate sets of association dues. In total, Eversource realized association dues savings of $1.1 million. The associated transmission savings based on the applicable allocation factor described below total $0.4 million.

11. Shareholder Services

Q54. HOW WAS EVERSOURCE ABLE TO GENERATE SAVINGS IN THE SHAREHOLDER SERVICES CATEGORY?

A54. Eversource, like most other large publicly-held corporations, expends money to cover a variety of services for its shareholders. Following the close of the merger, Eversource was able to realize savings in the area of Shareholder Services due to the elimination of duplicative shareholder related activities, such as conducting one annual shareholder meeting versus two (one for NU and one for NSTAR), reduced proxy services and payment of stock exchange fees. Additionally, incremental costs incurred per additional shareholder were reduced for Eversource due to economies of scale that NU and NSTAR were unable to achieve as standalone companies.

Q55. HOW DID EVERSOURCE CALCULATE THESE SAVINGS?

A55. For 2012 and 2013, Eversource examined its costs for Shareholder Services as compared to the combined Shareholder Services costs that NU and NSTAR incurred in 2011, the year before the merger. As shown in Exhibit No. ES-114, Eversource had savings of $0.3 million in 2012 and $0.6 million in 2013. To calculate these savings in later years, Eversource applied a GDP inflationary factor in both 2014 and 2015 to the savings amount from 2013. This is reasonable as the factors underlying the decreased costs in 2012 and 2013 were the same in both 2014 as 2015; namely, Eversource no longer has to pay for the shareholder services of both NU and NSTAR. Eversource realized $2.1 million in total savings related to shareholder services. *See* Exhibit No. ES-114. For transmission savings, Eversource Service applied the applicable allocation factor described below for a total of $0.4 million in transmission savings.

C. Enterprise-Wide O&M Expense Levels

Q56. DID EVERSOURCE EXAMINE HOW ITS TOTAL O&M EXPENSE LEVELS CHANGED FOLLOWING THE CONSUMMATION OF THE MERGER?

A56. Yes. Eversource examined the change in its O&M expense reductions following the merger from several perspectives. First, Eversource calculated and compared the change in its Non-Fuel electric O&M expense (the definition of "Non-Fuel" electric O&M is provided below) per FERC Form 1 data from 2011 to 2014 to that of 46 Edison Electric Institute ("EEI") member companies and to the general inflation rate over the same period as measured by the GDP Implicit Price Deflator.[18] This calculation allowed Eversource to identify how its post-merger Non-Fuel electric O&M expenses change compared to the industry and to inflation. Also, Eversource calculated the change in its total enterprise-wide O&M expense as reported

[18] For purposes of this comparison, Eversource combined the Non-Fuel electric O&M costs of the Legacy NU Companies and Legacy NSTAR Electric.

on its 2012-2015 10-K filings.[19] This analysis not only allowed Eversource to support the results of the Non-Fuel electric O&M expense analysis, but also to support that merger savings are driving Eversource's overall O&M expense levels lower. Details of the analysis and the results are provided below.

Q57. PLEASE DESCRIBE THE NON-FUEL ELECTRIC O&M EXPENSE ANALYSIS THAT EVERSOURCE CONDUCTED.

A57. Eversource endeavored to compare its post-merger electric O&M expense change versus that of other electric utilities in a manner that eliminated the impact of changes related to costs that either Eversource had little control over or that would not be materially impacted by Legacy NU's and Legacy NSTAR's decision to merge. To do this, Eversource compared the amount it spent on enterprise-wide non-fuel electric O&M expense (including A&G) between 2011 and 2014, to the non-fuel O&M change for 46 EEI member companies during the same time period (2014 is the last year of the analysis since annual FERC Form 1 data was being utilized, and 2014 is the last year available at the time of this filing). To make the analysis more useful, Eversource excluded from the comparison Power Production expenses (FERC Account Nos. 501 through 557), Transmission by Others (FERC

[19] For purposes of this comparison, Eversource combined the O&M costs of Legacy NU and Legacy NSTAR.

Account No. 565), Uncollectible expense (FERC Account No. 904), and Customer Assistance expense (FERC Account No. 908). As the primary exclusions here related to the costs of producing power, I will refer to the remaining costs as "Non-Fuel" electric O&M.

Q58. PLEASE FURTHER EXPLAIN THE NON-FUEL ELECTRIC O&M CALCULATION AND THE COSTS BEING EXCLUDED.

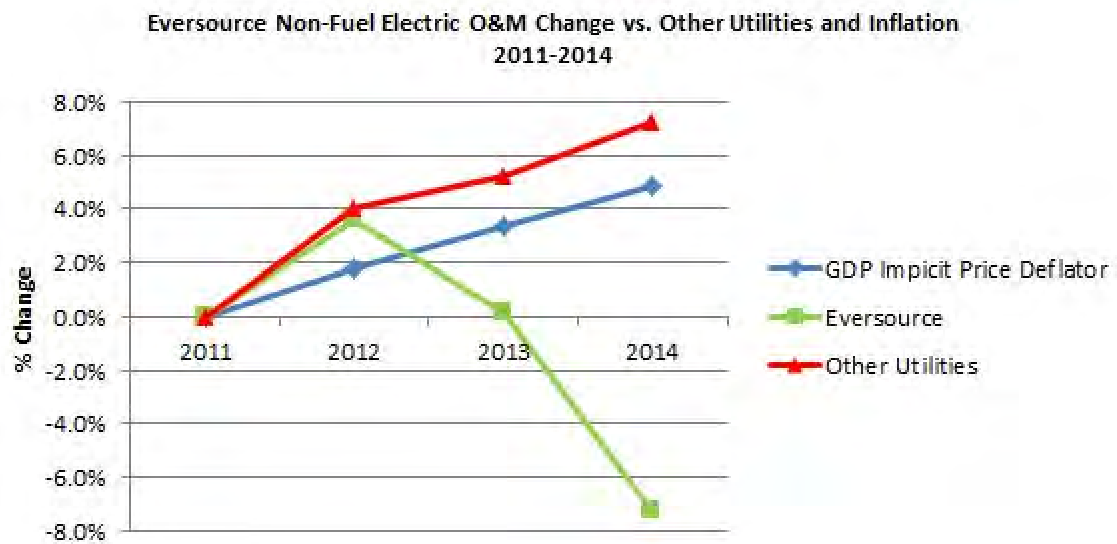
A58. As mentioned earlier, Eversource utilized FERC Form 1 data to perform the Non-Fuel electric O&M calculation for itself and 46 EEI companies. The data relied on by Eversource was obtained from SNL Financial ("SNL"), a premier provider of news, financial data and analysis on critical business sectors. Eversource has a service contract with SNL that includes access to FERC Form 1 data for U.S. electric utilities. Using this data resource, Eversource began the calculation with total electric O&M expenses (the sum of all FERC Account Nos. 500 to 935).

Eversource eliminated Power Production expenses (FERC Account Nos. 501 to 557), as these costs are determined by the market for utilities that have divested their generation resources. Eversource also eliminated Transmission by Others (FERC Account No. 565). In the merger, each of the subsidiary companies retained their previous legal entity status; therefore, each of the subsidiary entities still provide transmission for the others (and charge the relevant FERC approved rate) in the same manner as they did before the merger. Therefore, the merger did not (and more importantly could not) meaningfully impact the charges to this account. Finally, Eversource eliminated Uncollectible expense (FERC Account No. 904) and Customer Assistance expense (FERC Account No. 908). Uncollectible expense is primarily driven by economic conditions, while Customer Assistance expense (FERC Account No. 908) is primarily driven by the decisions of state regulatory agencies. Since year to year changes in costs in all of these areas would largely be unrelated to the merger, these costs were excluded to provide a proper comparison.

Q59. WHAT WERE THE RESULTS OF THIS ANALYSIS?

A59. The comparison showed that Eversource's Non-Fuel electric O&M expense decreased by approximately $84 million between 2011 and 2014. See Exhibit No. ES-118. This represents a 7.2% decrease in Non-Fuel electric O&M on a nominal basis. For the 46 EEI utilities, the average utility experienced an increase in Non-Fuel electric O&M costs of approximately 7.2% over the relevant time period. Further, inflation, as measured by the GDP inflationary factor, experienced a 4.9% increase over the same relevant time period. See Exhibit No. ES-115. This analysis indicates that despite the increasing Non-Fuel electric O&M expense experienced by Eversource's peers, as well as general inflationary trends, Eversource has experienced lower Non-Fuel electric O&M costs to the benefit of Eversource customers.

The line graph provided below provides a simple depiction of Eversource's experience as compared to others.

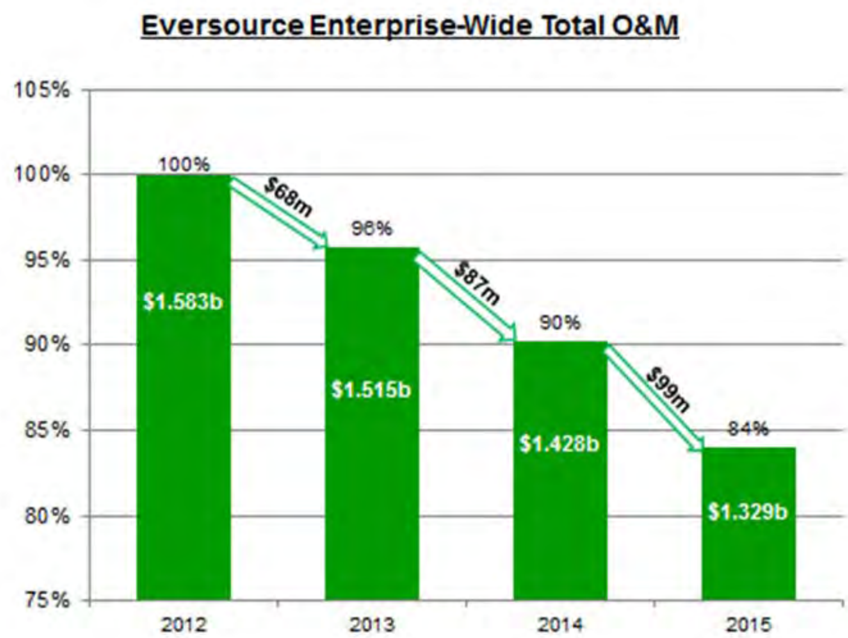


Q60. PLEASE DESCRIBE EVERSOURCE'S ANALYSIS OF THE CHANGE IN ITS TOTAL O&M AS REPORTED IN THE 10-K.

A60. Eversource also reviewed the change in its overall O&M as reported in its 10-K from 2012-2015. Although I believe it would still be possible to have merger savings even if Eversource's O&M didn't decrease, in this case the enterprise-wide total O&M *did* decrease. Eversource's 2013 total O&M decreased by $68 million as compared to 2012. In 2014, Eversource's total O&M decreased by an additional $87 million. In 2015, Eversource's total O&M decreased by an additional $99 million as compared to 2014. These are very real and meaningful savings that Eversource was able to pass along to its customers. The results of this comparison demonstrate that Eversource was not only able to offset wage increases and inflationary pressures, but that Eversource reduced overall costs (see chart below, which illustrates the total O&M decrease). In fact, Eversource experienced a combined total O&M decrease of $477 million from 2012 to 2015 ($68 million savings in 2013 as compared to 2012, $155 million in 2014 as compared to 2012 and $254 million in 2015 as compared to 2012) on a nominal basis.[20] The $477 million of actual enterprise O&M reduction is *more* than the $257 million of savings for 2013 through 2015 cited in the Merger Integration Report.[21] The results of both the Non-Fuel electric O&M analysis described earlier, and the total O&M analysis described here support the conclusion drawn in the Merger Integration Report that the merger savings Eversource has been able to achieve are resulting in lower expenses to Eversource's customers.

[20] During 2012-2014, Eversource continued expansion of its transmission plant. While total transmission O&M increased during this period (due to this expansion), transmission O&M (and transmission-related A&G) per dollar of net transmission plant declined 17%. *See* Exhibit No. ES-119.

[21] Exhibit ES-103, Table 1, lines 1-14 for 2013 through 2015.



D. Allocation of Savings to the Transmission Function

Q61. PLEASE EXPLAIN HOW EVERSOURCE ALLOCATED SAVINGS TO THE TRANSMISSION FUNCTION.

A61. In order to determine the amount of enterprise-wide merger savings that were related to the transmission function, Eversource used an allocation that was based on the nature of the savings that each company realized. Eversource examined each of these 11 categories of merger-related savings discussed above, and based on the nature of the savings, allocated them to each subsidiary and business segment using pre-determined allocators specifically identified in Eversource Service's FERC Form 60.[22] Corporate and administrative labor, benefits administration, information systems and A&G overhead savings were functionalized using a labor allocator. This allocator is a ratio of each subsidiary and business segment's labor to the total labor for all subsidiaries/business segments. This ratio best reflects the nature of such cost savings as corporate and administrative labor, benefits administration and information systems savings are driven substantially by labor. Insurance, professional services, external directors/trustees fees and association dues savings were functionalized using the Eversource common allocator. This allocator is a ratio based upon the average of the gross plant assets and net income for each subsidiary/business segment to the total average of gross plant assets and net income for all subsidiaries/business segments. This ratio best reflects the nature of such cost savings for these categories. For example, insurance tends to be driven off of the assets of the company, whereas net income is a relevant concern in these areas as well.

Shareholder services savings were functionalized using a revenue allocator. Contract services and materials and supply procurement savings,

[22] The one exception to this is the O&M allocator, which is not included among the FERC Form 60 allocators, and which was a necessary allocator for purposes of this analysis. The O&M allocator was calculated as the ratio of each subsidiary and business segment's O&M to the total O&M for all subsidiaries/business segments based on queries of Eversource's FERC Form 1 total O&M.

on the other hand, were functionalized based on total O&M expenses, since that best represents the nature of contract services cost savings.

All of the allocations noted above are the same allocation methodologies that were used in the state proceedings. The consistent use of allocations between the state proceedings and this proceeding is important and necessary to avoid any potential over or under representation of savings by business segment. The allocation percentages used are detailed in Exhibit No. ES-116.

V. COMPARISON OF MERGER COSTS AND BENEFITS

Q62. HOW DO THE TRANSMISSION MERGER-RELATED COSTS AND TRANSMISSION MERGER-RELATED SAVINGS COMPARE?

A62. As Ms. Cooper explains in her testimony, the transmission merger-related costs through September 30, 2015 total $37.4 million. The Eversource Companies are requesting approval to include these costs, plus up to an additional $1.5 million in future transmission merger-related costs, in their transmission rates, for a total of $38.9 million. As Ms. Cooper notes in her testimony, the Eversource Companies will make a compliance filing identifying the future transmission merger-related costs following the close of the hold harmless period, which is April 10, 2017. The transmission merger-related savings through September 30, 2015 total $58.7 million, and are

$19.8 million more than the transmission merger-related costs (including the future transmission merger-related costs) that the Eversource Companies are requesting approval to include in transmission rates. Since the Eversource Companies have demonstrated that all of their transmission merger-related costs are more than offset by transmission merger-related savings, their request to include the transmission merger-related costs in transmission rates should be approved.

Q63. DOES THIS CONCLUDE YOUR TESTIMONY?

A63. Yes, it does.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Eversource Energy Service Company) Docket No. ER16-___-000

AFFIDAVIT OF CHRISTINE L. VAUGHAN

Christine L. Vaughan, being first duly sworn, deposes and says that she is the Christine L. Vaughan referred to in the foregoing testimony, that she has read such testimony and is familiar with the contents thereof, and that the answers therein are true and correct to the best of her knowledge, information, and belief.

Christine L. Vaughan

Subscribed and sworn to before me this 22 day of February, 2016, by Christine L. Vaughan, proved to me on the basis of satisfactory evidence to be the person who appeared before me.

Notary Public

Commission Expires on: March 30, 2018

BARBARA J. MURPHY
Notary Public
COMMONWEALTH OF MASSACHUSETTS
My Commission Expires
March 30, 2018

Exhibit No. ES-101

2013 Merger Integration Annual Interim Report
(CT PURA Docket 14-05-06)

Eversource Energy Service Company

Merger Integration
2013 Annual Interim Report

Updated as of June 1, 2014

Northeast Utilities

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OVERVIEW

Methodology

This Merger Integration Report presents information, by functional area, on the merger-related costs incurred and savings achieved in the period between the closing date of the NSTAR/Northeast Utilities merger, April 10, 2012, and December 31, 2013.

The Merger Integration Report is organized to provide merger-related savings by functional area consistent with the Net Benefits Study filed in Docket Number 12-01-07, *Application for Approval of Holding Company Transaction Involving Northeast Utilities and NSTAR*. In each functional area, Northeast Utilities has identified the principal steps taken to achieve merger-related savings. To quantify merger-related savings, Northeast Utilities has tracked the savings attributable to merger-related integration activities in each functional area.

Differences from the Net Benefits Study: In the Net Benefits Study, the net merger-related savings were forecast by year, for a 10-year period, assuming a merger close in 2011. The Merger Savings Summary Table, below, shows that merger-related transaction costs were incurred starting in 2010. However, no savings were achieved until the start point of integration, which was the merger closing on April 10, 2012. In addition, this report shows that, although total overall savings are currently projected to exceed the projections encompassed in the Net Benefits Study, the specific areas from which savings have been achieved are different than originally forecast, with some areas yielding greater savings than anticipated and others yielding less. This result is to be expected due to the fact that the savings estimates in the Net Benefit Analysis were derived primarily on the basis of past experience with another merger. Under the circumstances of the NSTAR/Northeast Utilities merger, savings are arising in differing degrees in each functional area.

Computational Inputs: The Merger Savings Summary Table presents: (1) actual merger-related costs for 2010 through 2013; (2) actual merger-related savings through December 31, 2013; and (3) merger-related savings forecast for 2014 through 2022, consistent with the 10-year post-merger savings timeframe projected in the Net Benefit Study. The inflation factor used in the original Net Benefits Study is incorporated for 2014 and beyond, capturing the cost increases attributable to inflation that are avoided as a result of the elimination of operating costs.

Interim Results as of December 31, 2013

The Merger Integration Report shows that Northeast Utilities is projecting to exceed the merger-savings forecast developed for the Net Benefits Study. Specifically, the Net Benefits Study estimated net merger-related savings for the ten years following the merger to be $784 million on an enterprise-wide basis. The Merger Savings Summary Table, below, shows that the cumulative net savings projection is currently calculated to be $876.6 million over the 10-year period following the merger, 2012 through 2022. The projected savings of $876.6 million are net of $119.4 million of merger-related costs calculated in Table R, below. A total of $46 million of savings was paid to customers up front so that they would realize some of the tangible benefits of the merger upon the merger close, of which a total of $25 million in merger savings was paid out directly to CL&P customers.

In both Connecticut and Massachusetts, Northeast Utilities entered into merger-related settlement agreements designed to ensure net benefits to customers as a result of the merger. A principal term of the settlement agreements was the immediate credit to customers of a portion of the savings expected to result during the settlement periods. The up-front payment of $46 million in merger savings to customers caused the need to accelerate the achievement of savings as compared to the Net Benefits Study produced prior to the execution of the settlement agreements. Pursuant to the merger-related settlement agreements, executive retention and separation costs are *excluded* from the merger-related costs in this Annual Interim Report.

Savings quantifications through December 31, 2013 are presented herein for each functional area covered in the Net Benefits Study, with the original projection from Docket 12-01-07 shown first, followed by a computation of the 2013 Annual Interim savings summary, reflecting results through December 31, 2013.

Table 1

Merger Savings Summary - Rate Case Update

($ in Millions)

		Category	2010	2011	2012*	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022**	Total
1	A	Total Labor Savings	n/a	n/a	$ 8.6	$ 31.6	$ 36 3	$ 38.4	$ 40 5	$ 42.6	$ 44.8	$ 47.0	$ 49.2	$ 51.5	$ 12.9	$ 403.5
2	B	Administrative & General Overhead	n/a	n/a	-	0.6	0.6	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.2	6.6
3	C	Advertising	n/a	n/a	0.6	1 3	1.4	1.4	1.4	1.4	1.5	1.5	1.5	1.5	0.4	14.0
4	D	Benefits	n/a	n/a	-	18 2	20 9	23.7	26.6	29.6	32.7	35.8	39.1	42.4	10.6	279.6
5	E	Insurance	n/a	n/a	1 5	2 2	2 2	2 3	2 3	2.4	2.4	2.4	2.5	2.5	0.6	23.4
6	F	Information Systems	n/a	n/a	0.4	0.4	7 2	13.4	16 2	17.8	18.5	18.8	19.1	19.3	4.8	136.0
7	G	Professional Services	n/a	n/a	0 9	1.4	1.4	1.4	1 5	1 5	1.5	1.5	1.6	1.6	0.4	14.7
8	I	Shareholder Services	n/a	n/a	0 3	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.2	6.8
9	J	Vehicles	n/a	n/a	-	-	-	-	-	-	-	-	-	-	-	-
10	K	Directors Fees	n/a	n/a	0 2	1 2	1 2	1 2	1 2	1 3	1.3	1.3	1.3	1.3	0.3	11.8
11	L	Association Dues	n/a	n/a	0 1	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.1	3.9
12	M	Credit Facilities	n/a	n/a	-	-	-	-	-	-	-	-	-	-	-	-
13	N	Materials & Supply Procurement	n/a	n/a	0 3	1 1	1.6	2 1	2.6	3.0	3.5	3.9	4.4	4.8	1.2	28.7
14	P	Contract Services	n/a	n/a	1.0	3.6	4 5	5.4	6 3	7 1	7.9	8.7	9.5	10.3	2.6	67.0
15	R	Merger Related Cost	(18.7)	(23.7)	(53.4)	(17 9)	(5.6)	-	-	-	-	-	-	-	-	(119.4)
16		**Total Net Savings**	$ (18.7)	$ (23.7)	$ (39.4)	$ 44.8	$ 72 9	$ 91 1	$ 100.4	$ 108.6	$ 116.0	$ 123.0	$ 130.1	$ 137.3	$ 34.3	$ 876.6
17		Cummulative Savings	$ (18.7)	$ (42.5)	$ (81 9)	$ (37 1)	$ 35.8	$ 126.8	$ 227 2	$ 335.8	$ 451.8	$ 574.8	$ 704.9	$ 842.3	$ 876.6	
		*9 Months of Savings														
		**3 Months of Savings														

A. Corporate & Administrative Labor

Savings Rationale:

In the Net Benefits Study, Northeast Utilities forecast that reductions in personnel would result from the elimination of duplicative and overlapping Corporate and Administrative functions performed by the two pre-merger organizations. Forecasted savings did not include the results of potential re-engineering or downsizing opportunities that may be available to each company on a standalone basis.

Projected Savings:

In the Net Benefits Study, projected labor savings totaled $800,000 for 2011, $10.4 million for 2012 and $24.7 million for 2013, for cumulative savings of $35.9 million by December 31, 2013. The cumulative number of staffing reductions through the end of 2013 was forecast at 225 positions, with a cumulative total of 347 positions forecast for 2015.

Integration Activities:

Following the close of the merger, staffing reductions resulted from a reorganization of the Corporate & Administrative function and the elimination of redundant positions. Staffing changes were accelerated from the pace contemplated in the Net Benefits Study, due to the payment of an upfront savings credit to customers upon the merger close and the imposition of base-rate freezes. Because the positions eliminated were redundant positions in the new, combined operation, there is no impact to the ability of the Operating Companies to perform the work necessary to serve customers on a safe and reliable basis.

Savings Achieved:

As of December 31, 2013, merger-related staffing reductions and attrition accounted for the elimination of 257 positions since the merger close. Merger-related reductions are reductions related to NU's merger integration efforts, such as the consolidation of NU and NSTAR duplicate corporate functions or systems. Merger-Related job reductions do not include exits from the Company for other reasons such as retirements, resignations, terminations for cause, deaths, probationary terminations, NU's exit from certain competitive businesses or reductions due to normal day-to-day business and resource needs. In addition, labor savings from attrition is calculated as the difference between the number of employee exits and the number of new hires, as experienced in the respective period within the Northeast Utilities Service Company and, for former NSTAR employees, in the functional areas encompassed in the Corporate and Administrative group (because NSTAR did not have a service company structure prior to the merger).

These staffing changes have produced total savings through December 31, 2013 of $45.8 million including employee-benefits costs and other indirect expenses associated with labor. These savings could not be achieved without the incurrence of certain costs associated with labor reductions. Costs to achieve these savings are included in the computation of Merger-Related Costs.

Labor savings are quantified by calculating the actual annual salary and benefits for positions that were merger-related reductions and by taking an average salary for positions eliminated through attrition.

Savings associated with anticipated staffing reductions to implement the new IT organizational model are not included in this section as the bulk of the reductions did not occur in 2013. For purposes of the 2013 Annual Interim Report, anticipated future savings associated with the IT reorganization are included in the IT section below.

TABLE A
Corp & Admin Labor Savings Summary
($ in Millions)

		Original Net Benefit Analysis										
	Corp & Admin Labor	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Saving	2020 Savings	2021 Savings
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
1	Employee Reductions	25	100	100	100	22	-	-	-	-	-	-
2	Cummulative Employee Reductions	25	125	225	325	347	347	347	347	347	347	347
3	Corp & Admin Total Labor Savings	$0.8	$10.4	$24.7	$39.8	$50.1	$53.2	$54.6	$56.0	$57.5	$58.9	$60.3
4	Capitalization Rate	16.1%	16.1%	16 1%	16.1%	16.1%	16 1%	16.1%	16.1%	16.1%	16.1%	16.1%
5	Total O&M Savings	$0.7	$8.7	$20.7	$33.4	$42.0	$44.6	$45.9	$47.0	$48.2	$49.4	$50.7
6	Total Capitalized Savings	$0.1	$1.7	$4.0	$6.4	$8.0	$8.5	$8.8	$9.0	$9.2	$9.5	$9.7
7	Yearly Depreciation	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%
8	Rate Base Return	18.2%	18.2%	18 2%	18.2%	18.2%	18 2%	18.2%	18.2%	18.2%	18.2%	18.2%
9	2011	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
10	2012		$1.7	$1.6	$1.5	$1.5	$1.4	$1.4	$1.3	$1.3	$1.2	$1.2
11	2013			$4.0	$3.8	$3.7	$3.5	$3.41	$3.3	$3.2	$3.0	$2.9
12	2014				$6.4	$6.2	$5.9	$5.7	$5.5	$5.3	$5.1	$4.9
13	2015					$8.0	$7.7	$7.5	$7.2	$6.9	$6.7	$6.4
14	2016						$8.5	$8.2	$7.9	$7.6	$7.3	$7.1
15	2017							$8.8	$8.4	$8.1	$7.8	$7.5
16	2018								$9.0	$8.7	$8.3	$8.0
17	2019									$9.2	$8.9	$8.6
18	2020										$9.5	$9.1
19	2021											$9.7
20	Total Rate Base (sum lines 9 thru 19)	$0.1	$1.8	$5.7	$11.9	$19.5	$27.3	$35.0	$42.7	$50.4	$58.0	$65 5
21	Revenue Requirements (line 20 * line 8)	$0.0	$0.3	$1.0	$2.2	$3.5	$5.0	$6.4	$7.8	$9.1	$10.5	$11 9
22	O&M and Capital Return Savings (line 5 + line 21)	$0.7	$9.0	$21.8	$35.6	$45.6	$49.6	$52.2	$54.8	$57.4	$60.0	$62 5

		Preliminary Results										
	Corp & Admin Labor	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Saving	2020 Savings	2021 Savings
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
23	Inflation Rate			2.2%	2.5%	2.9%	2.9%	2.9%	2.9%	2 9%	2.9%	2.9%
24	Employee Reductions	-	200	57	-	-	-	-	-	-	-	-
25	Cummulative Employee Reductions	0	200	257	257	257	257	257	257	257	257	257
26	Corp & Admin Total Labor Savings	n/a	$9.7	$36.1	$40.4	$41.5	$42.7	$43.9	$45.2	$46.5	$47.9	$49.2
27	Capitalization Rate	n/a	13.4%	16.1%	16.1%	16.1%	16 1%	16.1%	16.1%	16 1%	16.1%	16.1%
28	Total O&M Savings	n/a	$8.4	$30.3	$33.9	$34.9	$35.9	$36.9	$38.0	$39.1	$40.2	$41.3
29	Total Capitalized Savings	n/a	$1 3	$5.8	$6.5	$6.7	$6.9	$7.1	$7.3	$7.5	$7.7	$7.9
30	Yearly Depreciation	n/a	3.3%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%
31	Rate Base Return	n/a	17.4%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18 2%	18.2%	18.2%
32	2011	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
33	2012		$1.3	$1.3	$1.2	$1.2	$1.1	$1.1	$1.0	$1.0	$1.0	$0.9
34	2013			$5.8	$5.6	$5.4	$5.2	$4.99	$4.8	$4.6	$4.5	$4.3
35	2014				$6.5	$6.2	$6.0	$5.8	$5.6	$5.4	$5.2	$5.0
36	2015					$6.7	$6.4	$6.2	$6.0	$5.7	$5.5	$5.3
37	2016						$6.9	$6.6	$6.4	$6.1	$5.9	$5.7
38	2017							$7.1	$6.8	$6.5	$6.3	$6.1
39	2018								$7.3	$7.0	$6.7	$6.5
40	2019									$7.5	$7.2	$6.9
41	2020										$7.7	$7.4
42	2021											$7.9
43	Total Rate Base (sum lines 32 thru 42)	n/a	$1.3	$7.1	$13.3	$19.4	$25.6	$31.7	$37.8	$43.8	$49.9	$56.0
44	Revenue Requirements (line 43 * line 31)	n/a	$0.2	$1.3	$2.4	$3.5	$4.6	$5.8	$6.9	$8.0	$9.1	$10.2
45	O&M and Capital Return Savings (line 28 + line 44)	n/a	$8.6	$31.6	$36.3	$38.4	$40.5	$42.6	$44.8	$47.0	$49.2	$51.5

		Variance (Preliminary Results vs Net Benefit Analysis)										
	Corp & Admin Labor	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Saving	2020 Savings	2021 Savings
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
46	Corp & Admin Total Labor Savings Variance (line 45 - line 22)	n/a	($0.4)	$9.8	$0.7	($7.2)	($9.1)	($9.6)	($10.0)	($10.4)	($10.7)	($11.1)

B. Administrative & General Overhead

Savings Rationale:

Administrative and general overhead costs include office supplies, telephone expenses, employee business expenses and other miscellaneous costs. Administrative and general overhead was anticipated to decrease as corporate personnel are reduced.

Projected Savings:

In the Net Benefits Study, projected administrative and general overhead savings totaled $300,000 for 2012 and $700,000 for 2013, for total savings of $1 million by December 31, 2013.

Integration Activities:

Following the close of the merger, staffing reductions resulted from a reorganization of the Corporate & Administrative function and the elimination of redundant positions. Initiatives include consolidated procurement for office supplies and paper across the combined Company resulting in improved pricing and rebates. Additionally, the Company was able to realize savings on printer and telephone cost. Due to the nature of these savings, there is no impact to the ability of the Operating Companies to perform the work necessary to serve customers on a safe and reliable basis.

Savings Achieved:

Through December 31, 2013, savings of approximately $700,000 have resulted from the creation of purchasing leverage due to the larger Northeast Utilities footprint, which allowed for negotiation of new reduced contracts for office supplies, paper supply, printer and telephone support. Annual savings based on integration efforts to date are in the range of $700,000.

TABLE B
Admin & General Savings Summary
($ in Millions)

		Original Net Benefit Analysis										
	Admin & General Overhead	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
1	Total Savings	$0.0	$0.3	$0.7	$1.1	$1.4	$1.5	$1.5	$1.5	$1.6	$1.6	$1.6
2	Capitalization Rate	16.1%	16.1%	16.1%	16.1%	16.1%	16.1%	16.1%	16.1%	16.1%	16.1%	16.1%
3	Total O&M Savings	$0.0	$0.2	$0.6	$1.0	$1.2	$1.3	$1.3	$1.3	$1.3	$1.3	$1.3
4	Total Capitalized Savings	$0.0	$0.0	$0.1	$0.2	$0.2	$0.2	$0.2	$0.2	$0.3	$0.3	$0.3
5	Yearly Depreciation	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%
6	Rate Base Return	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18 2%
7	2011	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
8	2012		$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
9	2013			$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
10	2014				$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.1	$0.1
11	2015					$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2
12	2016						$0.2	$0.2	$0.2	$0.2	$0.2	$0.2
13	2017							$0.2	$0.2	$0.2	$0.2	$0.2
14	2018								$0.2	$0.2	$0.2	$0.2
15	2019									$0.3	$0.2	$0.2
16	2020										$0.3	$0.2
17	2021											$0.3
18	Total Rate Base (sum lines 7 thru 17)	$0.0	$0.1	$0.2	$0.3	$0.6	$0.8	$1.0	$1 2	$1.4	$1.6	$1.8
19	Revenue Requirements (line 18 * line 6)	$0.0	$0.0	$0.0	$0.1	$0.1	$0.1	$0.2	$0 2	$0.3	$0.3	$0.3
20	O&M and Capital Return Savings (line 3 + line 19)	$0.0	$0.3	$0.6	$1.0	$1.3	$1.4	$1.5	$1.5	$1.6	$1.6	$1.7

		Preliminary Results										
	Admin & General Overhead	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
21	Inflation Rate			1 6%	2 4%	1 9%	1 9%	1 6%	1 5%	1 4%	1 4%	1 4%
22	Total Savings	n/a	$0.0	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7	$0.8	$0.8	$0.8
23	Capitalization Rate	n/a	13.4%	16.1%	16.1%	16.1%	16.1%	16.1%	16.1%	16.1%	16 1%	16.1%
24	Total O&M Savings	n/a	$0.0	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6	$0.7
25	Total Capitalized Savings	n/a	$0.0	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
26	Yearly Depreciation	n/a	3.3%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%
27	Rate Base Return	n/a	17.4%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18 2%	18.2%
28												
29	2011	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
30	2012		$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
31	2013			$0.1	$0.1	$0.1	$0 1	$0.1	$0.1	$0.1	$0.1	$0.1
32	2014				$0.1	$0.1	$0 1	$0.1	$0.1	$0.1	$0.1	$0.1
33	2015					$0.1	$0 1	$0.1	$0.1	$0.1	$0.1	$0.1
34	2016						$0 1	$0.1	$0.1	$0.1	$0.1	$0.1
35	2017							$0.1	$0.1	$0.1	$0.1	$0.1
36	2018								$0.1	$0.1	$0.1	$0.1
37	2019									$0.1	$0.1	$0.1
38	2020										$0.1	$0.1
39	2021											$0.1
40	Total Rate Base (sum lines 29 thru 39)	n/a	$0.0	$0.1	$0.2	$0.3	$0.4	$0.5	$0.6	$0.7	$0.8	$0.9
41	Revenue Requirements (line 40 * line 27)	n/a	$0.0	$0.0	$0.0	$0.1	$0 1	$0.1	$0.1	$0.1	$0.2	$0.2
42	O&M and Capital Return Savings (line 24 + line 41)	n/a	$0.0	$0.6	$0.6	$0.7	$0.7	$0.7	$0.7	$0.8	$0.8	$0.8

		Variance (Preliminary vs Net Benefit Analysis)										
	Admin & General Overhead	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
43	Admin & General Overhead	n/a	($0.3)	($0.0)	($0.4)	($0.6)	($0.7)	($0.7)	($0.8)	($0.8)	($0.8)	($0.9)
44	Total Savings	n/a	($0.3)	($0.0)	($0.4)	($0.6)	($0.7)	($0.7)	($0.8)	($0.8)	($0.8)	($0.9)

C. Advertising

Savings Rationale:

In the Net Benefits Study, Northeast Utilities forecast that the integration of corporate public-relations programs would eliminate the need for duplicative advertising-related design and production, and would reduce advertising fees.

Projected Savings:

In the Net Benefits Study, projected advertising savings totaled $200,000 for 2011, $700,000 for 2012 and $800,000 for 2013, for total savings of $1.7 million by December 31, 2013.

Integration Activities:

Following the close of the merger, Northeast Utilities cancelled the retainer for two advertising consulting agencies, whose services were not necessary under the combined company (savings of $600,000). Northeast Utilities also consolidated its media monitoring services and press release distribution account (savings of $160,000). Northeast Utilities reviewed its trade show participation, and as a combined company, was able to reduce the frequency of its participation (savings of $300,000). Savings were also achieved through (1) consolidation of corporate social responsibility reports and the elimination of paper production (savings of $177,000); (2) consolidation of existing NSTAR and NU Copyright Clearance Center contracts into one contract (savings of $2,000); (3) consolidation of the NSTAR and NU newsletters and collateral development documents from 45 publications to less than 10 (savings of $100,000). Due to the nature of these savings, there is no impact to the ability of the Operating Companies to perform the work necessary to serve customers on a safe and reliable basis.

Savings Achieved:

Through December 31, 2013, savings of approximately $2.0 million were achieved through integration and consolidation. Annual savings based on integration efforts to date are in the range of $1.3 million.

TABLE C
Advertising Savings Summary
($ in Millions)

		Original Net Benefit Analysis										
	Advertising	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
1	Advertising	$0.2	$0.7	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.9	$0.9
2	Total Savings	$0.2	$0.7	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.9	$0.9

		Preliminary Results										
	Advertising	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
3	Inflation Rate			1.6%	2.4%	1.9%	1.9%	1.6%	1.5%	1.4%	1.4%	1.4%
4	Advertising	n/a	$0.6	$1.3	$1.4	$1.4	$1.4	$1.4	$1.5	$1.5	$1.5	$1.5
5	Total Savings	n/a	$0.6	$1.3	$1.4	$1.4	$1.4	$1.4	$1.5	$1.5	$1.5	$1.5

		Variance (Preliminary vs. Net Benefit Analysis)										
	Advertising	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
6	Advertising	n/a	($0.1)	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6	$0.7	$0.7
7	Total Savings Variance	n/a	($0.1)	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6	$0.7	$0.7

D. Benefits Administration

Savings Rationale:

In the Net Benefits Study, Northeast Utilities forecast that cost savings in benefits administration could occur in several areas, primarily through increased purchasing power in negotiating third-party administration fees and integration of benefit plans.

Projected Savings:

In the Net Benefits Study, projected benefits-administration savings totaled $1.4 million for 2011, $5.8 million for 2012 and $6.1 million for 2013, for total annual savings of $13.3 million by December 31, 2013.

Integration Activities:

Northeast Utilities has undertaken several activities to integrate and align the benefit plans for employees. The Company first performed a comprehensive review of the legacy benefit plans enabling plan consolidation. Northeast Utilities also conducted RFPs for active and retiree health and welfare programs. Through this competitive bidding process, significant value was achieved in the following awards:

Provider	Coverage Type
Cigna	Medical and Prescription
Express Scripts	Prescription Drugs
Delta Dental	Dental
VSP	Vision
Minnesota Life	Life Insurance
KGA	Employee Assistance Program

Effective January 1, 2013, new health and welfare benefits were implemented for all non-represented employees. During 2013, as collective bargaining unit contracts expired, new health plans were successfully negotiated with the largest unions. By January 1, 2014, nearly all NU system employees will have the same standard health plan designs. In addition, effective April 2, 2013, retirement benefits to new Northeast Utilities employees will take the form of an enhanced defined contribution plan, instead of a defined benefit plan. This will reduce pension liabilities and cost volatility over time.

Due to the nature of these savings, there is no impact to the ability of the Operating Companies to perform the work necessary to serve customers on a safe and reliable basis.

Savings Achieved:

Through December 31, 2013, savings estimated at $27.2 million were achieved through integration and consolidation**.** Annual savings based on integration efforts to date are in the range of $27.2 million.

TABLE D
Benefits Administration Savings Summary
($ in Millions)

	Benefits Administration	Original Net Benefit Analysis										
		2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
1	Total Benefits Savings	$1.4	$5.8	$6.1	$6.4	$6.7	$7.0	$7.3	$7.7	$8.0	$8.4	$8.8
2	Capitalization Rate	40.6%	40.6%	40.6%	40.6%	40.6%	40.6%	40.6%	40.6%	40.6%	40.6%	40.6%
3	Total O&M Savings	$0.8	$3.4	$3.6	$3.8	$4.0	$4.1	$4.3	$4.6	$4.8	$5.0	$5.2
4	Total Capitalized Savings	$0.6	$2.3	$2.5	$2.6	$2.7	$2.8	$3.0	$3.1	$3.3	$3.4	$3.6
5	Yearly Depreciation	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%
6	Rate Base Return	18.2%	18 2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%
7	2011	$0.6	$0.5	$0.5	$0.5	$0 5	$0.5	$0.4	$0.4	$0.4	$0.4	$0.4
8	2012		$2.3	$2.3	$2.2	$2 1	$2.0	$1.9	$1.9	$1.8	$1.7	$1.7
9	2013			$2.5	$2.4	$2 3	$2.2	$2.1	$2.1	$2.0	$1.9	$1.8
10	2014				$2.6	$2 5	$2.4	$2.3	$2.2	$2.1	$2.1	$2.0
11	2015					$2.7	$2.6	$2.5	$2.4	$2.3	$2.2	$2.2
12	2016						$2.8	$2.7	$2.6	$2.5	$2.4	$2.3
13	2017							$3.0	$2.9	$2.8	$2.7	$2.6
14	2018								$3.1	$3.0	$2.9	$2.8
15	2019									$3.3	$3.1	$3.0
16	2020										$3.4	$3.3
17	2021											$3.6
18	Total Rate Base (sum lines 8 thru 17)	$0.6	$2.9	$5.3	$7.6	$10.1	$12.5	$15.0	$17.6	$20.2	$22.9	$25.6
19	Revenue Requirements (line 17 * line 7)	$0.1	$0.5	$1.0	$1.4	$1.8	$2.3	$2.7	$3.2	$3.7	$4.2	$4.7
20	O&M and Capital Return Savings (line 3 + line 19)	$0.9	$4.0	$4.6	$5.2	$5.8	$6.4	$7.1	$7.8	$8.4	$9.2	$9.9

		Preliminary Results										
	Benefits Administration	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
21	Inflation Rate			2.20%	4.46%	4.47%	4.77%	4.85%	4.81%	4.80%	4.81%	4.84%
22	Total Benefits Savings	n/a	$0.0	$27.2	$28.4	$29.7	$31.1	$32.6	$34.2	$35.8	$37.5	$39.4
23	Capitalization Rate	n/a	34.8%	40.6%	40.6%	40.6%	40.6%	40.6%	40.6%	40.6%	40.6%	40.6%
24	Total O&M Savings	n/a	$0.0	$16.2	$16.9	$17.6	$18.5	$19.4	$20.3	$21.3	$22.3	$23.4
25	Total Capitalized Savings	n/a	$0.0	$11.0	$11.5	$12.1	$12.6	$13.2	$13.9	$14.5	$15.2	$16.0
26	Yearly Depreciation	n/a	3.3%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%
27	Rate Base Return	n/a	17.4%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18 2%	18.2%
28	2011	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
29	2012		$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
30	2013			$11.0	$10.6	$10.2	$9.9	$9.5	$9.2	$8.8	$8.5	$8.2
31	2014				$11.5	$11.1	$10.7	$10.3	$9.9	$9.6	$9.2	$8.9
32	2015					$12.1	$11.6	$11.2	$10.8	$10.4	$10.0	$9.6
33	2016						$12.6	$12.2	$11.7	$11.3	$10.9	$10.5
34	2017							$13.2	$12.8	$12.3	$11.8	$11.4
35	2018								$13.9	$13.4	$12.9	$12.4
36	2019									$14.5	$14.0	$13.5
37	2020										$15.2	$14.7
38	2021											$16.0
39	Total Rate Base (sum lines 29 thru 38)	n/a	$0.0	$11.0	$22.2	$33.4	$44.8	$56.4	$68.2	$80.2	$92.5	$105.1
40	Revenue Requirements (line 38 * line 28)	n/a	$0.0	$2.0	$4.0	$6.1	$8.1	$10.2	$12.4	$14.6	$16.8	$19.1
41	O&M and Capital Return Savings (line 24 + line 40)	n/a	$0.0	$18.2	$20.9	$23.7	$26.6	$29.6	$32.7	$35.8	$39.1	$42.4

		Variance (Preliminary vs Net Benefit Analysis)										
	Benefits Administration	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
42	Benefits Administration	n/a	($4.0)	$13.6	$15.7	$17.9	$20.2	$22.5	$24 9	$27.4	$29 9	$32.5
43	Total Savings Variance	n/a	($4.0)	$13.6	$15.7	$17.9	$20.2	$22.5	$24 9	$27.4	$29 9	$32.5

E. Insurance

Savings Rationale:

In the Net Benefits Study, Northeast Utilities forecasted the combined company would be able to extend its coverage with its carriers over a larger asset and loss experience base, which would reduce overall cost. Combination of the insurance programs would also provide an opportunity to reassess needed coverage levels and related deductibles based on the loss experience and risk profile of the combined company.

Projected Savings:

In the Net Benefits Study, projected insurance savings totaled $500,000 for 2011, $2,200,000 for 2012 and $2,200,000 for 2013, for total savings of $4.9 million by December 31, 2013.

Integration Activities:

Following the merger close, Northeast Utilities reviewed existing insurance policies and coverage and combined the individual legacy company policies as those policies expired, resulting in better pricing for the combined company than on a stand-alone basis. Due to the nature of these savings, there is no impact to the ability of the Operating Companies to perform the work necessary to serve customers on a safe and reliable basis.

Savings Achieved:

Through December 31, 2013, cumulative savings of approximately $3.7 million were achieved through integration and consolidation. Annual savings based on integration efforts to date are in the range of $2.2 million.

TABLE E
Insurance Savings Summary
($ in Millions)

	Insurance	Original Net Benefit Analysis										
		2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
1	Insurance	$0.5	$2.2	$2.2	$2.3	$2.3	$2.4	$2.4	$2.4	$2.5	$2.5	$2.5
2	Total Savings	$0.5	$2.2	$2.2	$2.3	$2.3	$2.4	$2.4	$2.4	$2.5	$2.5	$2.5

	Insurance	Preliminary Results										
		2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
3	Inflation Rate			1.6%	2.4%	1.9%	1.9%	1.6%	1.5%	1.4%	1.4%	1.4%
4	Insurance	n/a	$1.5	$2.2	$2.2	$2.3	$2.3	$2.4	$2.4	$2.4	$2.5	$2.5
5	Total Savings	n/a	$1.5	$2.2	$2.2	$2.3	$2.3	$2.4	$2.4	$2.4	$2.5	$2.5

	Insurance	Variance (Preliminary vs Net Benefit Analysis)										
		2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
6	Insurance	n/a	($0.7)	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)
7	Total Savings Variance	n/a	($0.7)	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)

F. Information Systems

Savings Rationale:

In the Net Benefits Study, IT-related capital savings were expected to result from the avoidance and elimination of duplicate or unnecessary system development expenditures and the creation of a common IT infrastructure and architecture across the combined company. In addition, the combined entity was expected to avoid system development costs. Also in the Nets Benefit Study, IT-related O&M cost savings were expected as a result of the avoidance of leasing desktop computers because of the reduced number of positions requiring workstations. Savings were expected to occur due to the elimination of software and hardware leases, and associated maintenance, resulting from the migration to a common operating platform.

Projected Savings:

In the Net Benefits Study, projected IT savings totaled $200,000 for 2011, $2,300,000 for 2012 and $5,400,000 for 2013, for total savings of $7.9 million by December 31, 2013.

Integration Activities:

Northeast Utilities has consolidated its Corporate Income Tax Return Reporting Systems and Claims Management Systems. The Company has also upgraded and integrated the existing PowerPlant installations and implemented one budgeting system across the operating companies. In addition, Northeast Utilities has consolidated email systems**,** eliminating issues with email compatibility and calendaring and reducing email support cost. Northeast Utilities has also addressed an immediate need to share applications among the operating companies by expanding cross-company application sharing environments in both Westwood, MA & Windsor, CT. The cost of these initiatives is included as Merger-Related Costs, below.

In October 2013, Northeast Utilities announced an initiative involving the reorganization of the Information Technology department. At this stage Northeast Utilities has incurred costs in furtherance of this initiative with savings anticipated to begin in mid-2014 and future years. A preliminary estimate of the net labor savings is included in this section and the associated costs are included in the Merger-Related Cost section. This estimate is preliminary and will be refined in future interim reports. The estimate includes labor savings from an anticipated reduction in NU staff; estimated contracted savings from elimination of current contractors and the estimated cost of new contractors. The net amount is included in the O&M savings amount. This total will be further refined as actual savings and costs are known.

The reorganization of the IT Organization will have no impact on the ability of the Operating Companies to perform the work necessary to serve customers on a safe and reliable basis under routine conditions and under storm conditions.

Savings Achieved:

As of December 31, 2013, O&M savings of approximately $800,000 were achieved through integration and consolidation. Additional net savings are anticipated to result in 2014 as the IT reorganization is implemented.

TABLE F
IT O&M & Capital Savings Summary
($ in Millions)

	IT Savings	Original Net Benefit Analysis										
		2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
1	Total O&M Savings	$0 1	$0 9	$2 3	$3 6	$4 6	$4 9	$5 0	$5 1	$5 2	$5 4	$5 5
2	Total Capitalized Savings	$0 1	$1 3	$3 1	$5 0	$6 3	$6 7	$6 9	$7 1	$7 2	$7 4	$7 6
3	O&M and Capital Return Savings (line 1 + line 2)	$0 2	$2 3	$5 4	$8 7	$10 9	$11 6	$11 9	$12 2	$12 5	$12 8	$13 1

	IT Savings	Preliminary Results										
		2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
4	Inflation Rate			1.6%	2.4%	1.9%	1.9%	1.6%	1.5%	1.4%	1.4%	1.4%
5	Total O&M Savings	n/a	$0 4	$0 4	$7 2	$13 4	$16 2	$17 8	$18 5	$18 8	$19 1	$19 3
6	Total Capitalized Savings	n/a	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0
7	Yearly Depreciation	n/a	3 3%	3 7%	3 7%	3 7%	3 7%	3 7%	3 7%	3 7%	3 7%	3 7%
8	Rate Base Return	n/a	17 4%	18 2%	18 2%	18 2%	18 2%	18 2%	18 2%	18 2%	18 2%	18 2%
9	2011	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
10	2012		$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0
11	2013			$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0
12	2014				$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0
13	2015					$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0
14	2016						$0 0	$0 0	$0 0	$0 0	$0 0	$0 0
15	2017							$0 0	$0 0	$0 0	$0 0	$0 0
16	2018								$0 0	$0 0	$0 0	$0 0
17	2019									$0 0	$0 0	$0 0
18	2020										$0 0	$0 0
19	2021											$0 0
20	Total Rate Base (sum lines 9 thru 19)	n/a	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0
21	Revenue Requirements (line 20 * line 8)	n/a	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0
22	O&M and Capital Return Savings (line 5 + line 21)	n/a	$0 4	$0 4	$7 2	$13 4	$16 2	$17 8	$18 5	$18 8	$19 1	$19 3

	IT Savings	Variance (Preliminary vs Net Benefit Analysis)										
		2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
23	IT O&M & Capital	n/a	($1 8)	($5 0)	($1 4)	$2 5	$4 6	$5 9	$6 4	$6 3	$6 3	$6 2
24	Total Savings Variance	n/a	($1 8)	($5 0)	($1 4)	$2 5	$4 6	$5 9	$6 4	$6 3	$6 3	$6 2

G. Professional Services

Rationale for Savings:

In the Net Benefits Study, Northeast Utilities projected that it would work to consolidate and reduce professional-services activities through economies of scope and elimination of non-recurring duplicate services and increased utilization of a broader skill base. It was also contemplated that audit and legal services costs could be reduced to eliminate duplication.

Projected Savings:

In the Net Benefits Study, projected professional services savings totaled $700,000 for 2011, $3,000,000 for 2012 and $3,000,000 for 2013, for total savings of $6.7 million by December 31, 2013.

Integration Activities:

P-Card/T&E Card Consolidation: This savings project consolidated the existing corporate procurement credit cards with a single vendor, resulting in increased volume rebates. The new corporate procurement cards were fully rolled out to Northeast Utilities employees in the second half of 2013 (savings of $130,000 annually).

Staff Augmentation Contract Consolidation (Guidant): This savings project is based on consolidating the management of staff augmentation into a single third party vendor to leverage volume and reduce administration/management fees. Northeast Utilities is currently tracking ahead of projected savings by moving from Zempleo to Guidant for payroll services (savings of $100,000 annually).

External Auditor Consolidation: Northeast Utilities terminated the duplicative relationship with the NSTAR auditors (PwC) by keeping the existing the auditors (Deloitte) (savings of approximately $700,000 annually).

Eliminate Westlaw Contract: Northeast Utilities integrated the NSTAR Westlaw service into the Northeast Utilities service at no additional cost (savings of $65,000 annually).

Eliminate Nixon Peabody Lease: Northeast Utilities cancelled the lease for office space at Nixon Peabody in Boston, MA, as the space is no longer needed (savings of $60,000 in annually)**.**

Eliminate Towers Watson NSTAR Fair Values Fees: Savings were derived by avoiding the duplicative engagement of Towers Watson to calculate performance share compensation (savings of $15,000 annually).

Financial Reporting Integration: This effort involved insourcing XBRL/Edgarization 10-K filing requirements. Northeast Utilities completes this financial reporting process without external providers. The savings are derived from terminating a third party contract which was providing these services for NSTAR (savings of $120,000 annually).

Consolidation of 3rd Party Call Center Contracts: Post merger, Northeast Utilities was able to consolidate the 3rd party call center contract under one contract (savings of $120,000 annually).

Due to the nature of these savings, there is no impact to the ability of the Operating Companies to perform the work necessary to serve customers on a safe and reliable basis.

Savings Achieved:

Through December 31, 2013, savings of approximately $2.3 million were achieved through integration and consolidation. Annual savings based on integration efforts to date are in the range of $1.4 million.

TABLE G
Professional Services Savings Summary
($ in Millions)

		Original Net Benefit Analysis										
	Professional Services	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
1	Professional Services	0.7	3.0	3.0	3.1	3.2	3.2	3.3	3.3	3.4	3.4	3.5
2	Total Savings	$0.7	$3.0	$3.0	$3.1	$3.2	$3.2	$3.3	$3.3	$3.4	$3.4	$3.5

		Preliminary Results										
	Professional Services	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
3	Inflation Rate			1.6%	2.4%	1.9%	1.9%	1.6%	1.5%	1.4%	1.4%	1.4%
4	Professional Services	n/a	0.9	1.4	1.4	1.4	1.5	1.5	1.5	1.5	1.6	1.6
5	Total Savings	n/a	$0.9	$1.4	$1.4	$1.4	$1.5	$1.5	$1.5	$1.5	$1.6	$1.6

		Variance (Preliminary vs Net Benefit Analysis)										
	Professional Services	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
6	Professional Services	n/a	(2.1)	(1.7)	(1.7)	(1.7)	(1.8)	(1.8)	(1.8)	(1.8)	(1.9)	(1.9)
7	Total Savings Variance	n/a	($2.1)	($1.7)	($1.7)	($1.7)	($1.8)	($1.8)	($1.8)	($1.8)	($1.9)	($1.9)

H. Facilities

Savings Rationale:

In the Net Benefits Study, Northeast Utilities indicated that, normally, a post-merger entity will consolidate selected facilities, including service centers, garages, data centers, meter shops, warehousing and other corporate facilities. However, due to the geographic disparity of the post-merger operating companies, facilities integration was not anticipated.

Projected Savings:

The Net Benefits Study did not contemplate any savings associated with facilities consolidation.

Integration Activities:

Since the merger, Northeast Utilities has undertaken a facilities review across its entire service territory to ensure that its current facilities sufficiently meet operational needs. This initiative follows the merger, but is not tied directly to integration activities.

Currently, Northeast Utilities operates 102 work sites (78 owned, 24 leased), encompassing 161 buildings with approximately five million square feet of space. Following the merger, NU's integration team performed a comprehensive facilities review, assessing all work centers, service centers, line shops, warehouses, corporate offices and call centers. In addition to geographic distribution, occupancy levels and functionality, the integration team reviewed the future capital needs and investment required at each facility for maintenance and enhancements. As a result of this comprehensive facilities review, NU is expecting to implement certain facilities changes in the next 15 months.

Savings Achieved:
No savings were achieved through December 31, 2013 associated with facilities. CL&P filed its facilities consolidation plan with the Authority in Docket 13-11-13 and filed an application in Docket 14-04-12 for approval from PURA to sell seven sites. The financial impact of anticipated facility changes is discussed in the pre-filed testimony of Michael J. Mahoney.

I. Shareholder Services

Rationale for Savings:

Cost savings are expected to result from the elimination of duplicative shareholder related activities, such as conducting the annual shareholder meeting, proxy services and payment of stock exchange fees. The combination will reduce incremental costs per additional shareholder due to economies of scale.

Projected Savings:

In the Net Benefits Study, projected shareholder services savings totaled $100,000 for 2011, $500,000 for 2012 and $500,000 for 2013, for total savings of $1.1 million by December 31, 2013.

Integration Activities:

Transfer Agent Services: NU issued a Request for Proposals (RFP) for the provision of transfer agent services. The transfer agent's responsibilities include maintaining the company's shareholder records, distributing quarterly dividend checks and reinvestment plan statements for the registered shareholder base as well as tax information related to dividends and the sale of shares. It also includes annual distribution of proxy materials to registered shareholders in advance of the Company's annual meeting of shareholders and compliance with escheatment laws. Computershare was chosen to serve as the Company's transfer agent under a three-year contact. Additionally, NU amended various provisions of the NU dividend reinvestment plan (DRP) to mirror the legacy NSTAR dividend reinvestment plan. As a result of this action, the Company was able to avoid the cost and inconvenience to participants of re-registering nearly 10,000 NSTAR registered holders in the NU DRP. By mirroring the NSTAR plan, the Company was also able to lower reinvestment fees considerably for legacy NU shareholders.

Thomson Reuters Investor Relations (IR) Services: Prior to the merger, NU and NSTAR had contracts in place for various Investor Relations services including management of an Investor Relations website at NSTAR, with Thomson Reuters. Thomson Reuters continues to provide more abbreviated services under a new consolidated three-year contract. A large portion of these costs are covered by a subsidy from the New York Stock Exchange, Inc. (NYSE) that has historically been available to NU.

IPREO: Prior to the merger, NSTAR had retained IPREO, a market surveillance firm, to assist with its ongoing Investor Relations program. IPREO's services continue with NU but at a reduced overall cost as its services qualify under the aforementioned subsidy from the NYSE.

Proxy Solicitor: Prior to the merger, NU and NSTAR each retained a proxy solicitor to provide services related to each company's annual meeting of shareholders. An RFP was issued and four companies provided bids. After a comprehensive review of the bids, AST Phoenix Advisory Partners was chosen to provide proxy services for the combined company at a cost that is less than the sum of what each company paid for these services in the past.

Annual Meeting, Proxy Mailings, Broadridge: In conjunction with the annual meeting of shareholders, NU and NSTAR distributed proxy materials to its shareholders through an independent agent, Broadridge. The fee consists primarily of postage and related costs to distribute proxy materials. The fee is also a function of the number of accounts managed by Broadridge. The number of accounts now managed by Broadridge after the merger's completion is less than the sum of the NU and NSTAR accounts prior to the merger.

Annual Report to Shareholders: Prior to the merger, NU and NSTAR produced an Annual Report to Shareholders for distribution to their shareholders in advance of their annual meetings. After the merger, the "combined NU" produced an annual report at a cost that was significantly less than the sum of what it cost each company to produce its own 2011 annual report. NU also utilized a "Notice & Access" approach in the distribution of its 2012 report. This approach offers shareholders the opportunity to view its proxy materials on the Internet instead of receiving a copy in the mail and reduces both printing and mailing costs.

Rating Agencies: Northeast Utilities negotiated lower rating agency fees due to the larger size of the merged company.

Due to the nature of these savings, there is no impact to the ability of the Operating Companies to perform the work necessary to serve customers on a safe and reliable basis.

Savings Achieved:
Through December 31, 2013, savings of approximately $900,000 were achieved through integration and consolidation. Annual savings based on integration efforts to date are in the range of $600,000.

TABLE I
Shareholder Services Savings Summary
($ in Millions)

	Shareholder Services	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
		Original Net Benefit Analysis										
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
1	Shareholder Services	0.1	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
2	Total Savings	$0.1	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5

	Shareholder Services	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
		Preliminary Results										
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
3	Inflation Rate			1.6%	2.4%	1.9%	1.9%	1.6%	1.5%	1.4%	1.4%	1.4%
4	Shareholder Services	n/a	0.3	0.6	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7
5	Total	n/a	$0.3	$0.6	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7

	Shareholder Services	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
		Variance (Preliminary vs Net Benefit Analysis)										
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
6	Shareholder Services	n/a	(0.2)	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
7	Total Savings Variance	n/a	($0.2)	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2

J. Vehicles

Savings Rationale:

Prior to the merger, Northeast Utilities contemplated that the combined company will reduce the total number of corporate A&G employees. As a result of the reduction in the number of employees, the new company will use fewer passenger cars. Savings will be realized through reduced total operating costs for passenger cars. Reduced reimbursable mileage is reflected in Section D: Administrative and General Overhead.

Projected Savings:

In the Net Benefits Study, there were modest amounts of projected vehicle cost savings for 2011, 2012 and 2013.

Integration Activities:

Vehicle savings achieved through December 31, 2013 were modest as anticipated and are not individually quantified as yet.

TABLE J
Vehicles Savings Summary
($ in Millions)

	Vehicles	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
		Original Net Benefit Analysis										
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
1	Total Transportation Cost	$0.0	$0.0	$0.0	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
2	Total	$0.0	$0.0	$0.0	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1

	Vehicles	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
		Preliminary Results										
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
3	Inflation Rate			1.6%	2.4%	1.9%	1.9%	1.6%	1.5%	1.4%	1.4%	1.4%
4	Total Transportation Cost	n/a	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
5	Total	n/a	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0

	Vehicles	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
		Variance (Preliminary vs Net Benefit Analysis)										
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
6	Total Transportation Cost	n/a	($0.0)	($0.0)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)
7	Total Savings Variance	n/a	($0.0)	($0.0)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)

K. External Directors/Trustee Fees

Savings Rationale:

Prior to the merger, NSTAR and NU each had separate boards of trustees. With the merger of NSTAR and NU, the number of independent trustees could be reduced.

Projected Savings:

In the Net Benefits Study, projected external directors/trustee fee savings totaled $300,000 for 2011, $1,400,000 for 2012 and $1,400,000 for 2013, for total savings of $3.1 million by December 31, 2013.

Integration Activities:

Following the merger closing date, Northeast Utilities combined the NU and NSTAR boards. The new board structure has reduced the number of Trustees and revised the compensation model. This action will result in approximately $1.2 million in annual savings beginning in 2013.

Due to the nature of these savings, there is no impact to the ability of the Operating Companies to perform the work necessary to serve customers on a safe and reliable basis.

Savings Achieved:

Through December 31, 2013, total savings in this functional area total $1.4 million. Annual savings based on integration efforts to date are in the range of $1.2 million.

TABLE K
External Directors Savings
($ in Millions)

	External Directors / Trustee Fees	Original Net Benefit Analysis										
		2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
1	Total Fees	$0.3	$1.4	$1.4	$1.4	$1.5	$1.5	$1.5	$1.5	$1.6	$1.6	$1.6
2	Total	$0.3	$1.4	$1.4	$1.4	$1.5	$1.5	$1.5	$1.5	$1.6	$1.6	$1.6

	External Directors / Trustee Fees	Preliminary Results										
		2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
3	Inflation Rate			1.6%	2.4%	1.9%	1.9%	1.6%	1.5%	1.4%	1.4%	1.4%
4	Total Fees	n/a	$0.2	$1.2	$1.2	$1.2	$1.2	$1.3	$1.3	$1.3	$1.3	$1.3
5	Total	n/a	$0.2	$1.2	$1.2	$1.2	$1.2	$1.3	$1.3	$1.3	$1.3	$1.3

	External Directors / Trustee Fees	Variance (Preliminary vs Net Benefit Analysis)										
		2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
6	Total Fees	n/a	($1.1)	($0.2)	($0.3)	($0.3)	($0.3)	($0.3)	($0.3)	($0.3)	($0.3)	($0.3)
7	Total Savings Variance	n/a	($1.1)	($0.2)	($0.3)	($0.3)	($0.3)	($0.3)	($0.3)	($0.3)	($0.3)	($0.3)

L. Association Dues

Savings Rationale:

In the Net Benefits Study, savings were forecast to result from the elimination of EEI membership dues model and other dues that would be reduced with a consolidated entity. The EEI dues model includes decreased rates after the first 500,000 customers and $500 million in electric revenues, decreasing the cost for the combined new company with greater revenue and a larger customer base as compared with two stand-alone companies.

Projected Savings:

In the Net Benefits Study, projected association dues savings totaled $100,000 for 2011, $400,000 for 2012 and $400,000 for 2013, for total savings of $900,000 by December 31, 2013.

Integration Activities:

Following the merger close, Northeast Utilities was able to reduce EEI dues because of the size of the combined company. Also, all professional memberships and corporate sponsorships/association fees were reviewed and duplicates were eliminated. Due to the nature of these savings, there is no impact to the ability of the Operating Companies to perform the work necessary to serve customers on a safe and reliable basis.

Savings Achieved

Through December 31, 2013, total savings in this functional area total $500,000. Annual savings based on integration efforts to date are in the range of $400,000.

TABLE L
Association Dues Savings Summary
($ in Millions)

	Association Dues	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
		Original Net Benefit Analysis										
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
1	Association Dues	$0.1	$0.4	$0.4	$0.4	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5
2	Total	$0.1	$0.4	$0.4	$0.4	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5

	Association Dues	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
		Preliminary Results										
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
3	Inflation Rate			1.6%	2.4%	1.9%	1.9%	1.6%	1.5%	1.4%	1.4%	1.4%
4	Association Dues	n/a	$0.1	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4
5	Total	n/a	$0.1	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4

	Association Dues	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
		Variance (Preliminary vs. Net Benefit Analysis)										
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
6	Association Dues	n/a	($0.4)	($0.0)	($0.0)	($0.0)	($0.0)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)
7	Total Savings Variance	n/a	($0.4)	($0.0)	($0.0)	($0.0)	($0.0)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)

M. Credit Facilities

Savings Rationale:

Prior to the merger, neither NSTAR nor Northeast Utilities fully utilized its respective credit lines. The Net Benefits Study anticipated that the post-merger organization would be in a better position to schedule its cash flow needs and, as a result, would be in a position to reduce the level of combined credit lines. Savings were also contemplated through avoided commitment fees on the underlying credit lines.

Projected Savings:

In the Net Benefits Study, there were minimal savings associated with credit facilities forecast through December 31, 2013.

Integration Activities:

Consistent with the Net Benefits Analysis, restructuring of credit facilities produced modest savings by December 31, 2013, which are not separately quantified as yet.

TABLE M
Credit Facilities Savings Summary
($ in Millions)

	Credit Facilities	Original Net Benefit Analysis										
		2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
1	Credit Facility Fees	$0.0	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
2	Total	$0.0	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1

	Credit Facilities	Preliminary Results										
		2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
3	Inflation Rate			1.6%	2.4%	1.9%	1.9%	1.6%	1.5%	1.4%	1.4%	1.4%
4	Credit Facility Fees	n/a	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
5	Total	n/a	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0

	Credit Facilities	Variance (Preliminary vs. Net Benefit Analysis)										
		2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
6	Credit Facility Fees	n/a	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)
7	Total Savings Variance	n/a	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)

N. Materials & Supply Procurement

Savings Rationale:

In the Net Benefits Study, savings were expected from increased standardization, purchasing power, and vendor consolidation.

Projected Savings:

In the Net Benefits Study, projected savings for materials and supply procurement totaled $2.6 million for 2011, $10.6 million for 2012 and $10.9 million for 2013.

Integration Activities:

> **Procurement - Contract Rationalization Savings Initiative:** This saving project started the contract consolidation process by focusing on common vendors of NSTAR and Northeast Utilities within the top 80 percent of spend. Through consolidation of vendors and vendor concessions, savings were identified. Ongoing efforts are continuing to identify savings with the smaller common vendors of Northeast Utilities. The effort has lead to material and supply savings of approximately $1.3 million in 2012 and $3.2 million in 2013.
>
> **Standardization & Consolidation of Materials Initiative:** Northeast Utilities is in the process of reviewing materials function across the enterprise. Currently 12 commodity groups consisting of 314 items have been reviewed. To date, the review has led to 104 items being eliminated leading to lower ongoing material cost.

Due to the nature of these savings, there is no impact to the ability of the Operating Companies to perform the work necessary to serve customers on a safe and reliable basis.

Savings Achieved

Through December 31, 2013, total savings of $4.5 million were achieved. Annual savings based on integration efforts to date are in the range of $3.2 million.

TABLE N
Materials & Supply Savings Summary
($ in Millions)

		Original Net Benefit Analysis										
	Material and Supply Procurement	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
1	Material & Supply Procurement	$2.6	$10.6	$10.9	$11 2	$11.4	$11.6	$11.8	$12.0	$12.1	$12.3	$12.5
2	Capitalization Rate	85.7%	85.7%	85.7%	85.7%	85.7%	85.7%	85.7%	85.7%	85.7%	85.7%	85.7%
3	Total O&M Savings	$0.4	$1.5	$1.6	$1.6	$1.6	$1.7	$1.7	$1.7	$1.7	$1.8	$1.8
4	Total Capitalized Savings	$2.2	$9.1	$9.4	$9.6	$9.8	$10.0	$10.1	$10.3	$10.4	$10.6	$10.7
5	Yearly Depreciation	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%
6	Rate Base Return	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18 2%	18.2%
7	2011	$2.2	$2.1	$2.1	$2.0	$1.9	$1.8	$1.8	$1.7	$1.6	$1.6	$1.5
8	2012		$9.1	$8.8	$8.4	$8.1	$7.8	$7.5	$7 3	$7.0	$6.7	$6.5
9	2013			$9.4	$9.0	$8.7	$8.4	$8.0	$7.8	$7.5	$7.2	$6.9
10	2014				$9.6	$9.2	$8.9	$8.6	$8 2	$7.9	$7.6	$7.4
11	2015					$9.8	$9.4	$9.1	$8.7	$8.4	$8.1	$7.8
12	2016						$10.0	$9.6	$9 2	$8.9	$8.6	$8.2
13	2017							$10 1	$9.7	$9.4	$9.0	$8.7
14	2018								$10.3	$9.9	$9.5	$9.2
15	2019									$10.4	$10.0	$9.7
16	2020										$10.6	$10.2
17	2021											$10.7
18	Total Rate Base (sum lines 7 thru 17)	$2.2	$11.2	$20.2	$29.0	$37.7	$46.3	$54.7	$62.9	$71.0	$78.9	$86.7
19	Revenue Requirements (line 18 * line 6)	$0.4	$2.0	$3.7	$5.3	$6.8	$8.4	$9.9	$11.4	$12.9	$14.3	$15.7
20	O&M and Capital Return Savings (line 3 + line 19)	$0.8	$3.6	$5.2	$6.9	$8.5	$10.1	$11.6	$13.1	$14.6	$16.1	$17.5

	Material and Supply Procurement	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
		Preliminary Results										
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
21	Inflation Rate			1 6%	2 4%	1 9%	1 9%	1 6%	1 5%	1 4%	1 4%	1 4%
22	Material & Supply Procurement	n/a	$1.3	$3.2	$3.2	$3.3	$3.4	$3.4	$3.5	$3.5	$3.6	$3.6
23	Capitalization Rate	n/a	92.0%	85.7%	85.7%	85.7%	85.7%	85.7%	85.7%	85.7%	85.7%	85.7%
24	Total O&M Savings	n/a	$0.1	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5
25	Total Capitalized Savings	n/a	$1.2	$2.7	$2.8	$2.8	$2.9	$2.9	$3.0	$3.0	$3.1	$3.1
26	Yearly Depreciation	n/a	3 3%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%
27	Rate Base Return	n/a	17.4%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%
28	2011	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
29	2012		$1.2	$1.1	$1.1	$1.1	$1.0	$1.0	$0.9	$0.9	$0.9	$0.8
30	2013			$2.7	$2.6	$2.5	$2.4	$2.3	$2.2	$2.2	$2.1	$2.0
31	2014				$2.8	$2.7	$2.6	$2.5	$2.4	$2.3	$2.2	$2.1
32	2015					$2.8	$2.7	$2.6	$2.5	$2.4	$2.3	$2.3
33	2016						$2.9	$2.8	$2.7	$2.6	$2.5	$2.4
34	2017							$2.9	$2.8	$2.7	$2.6	$2.5
35	2018								$3.0	$2.9	$2.8	$2.7
36	2019									$3.0	$2.9	$2.8
37	2020										$3.1	$2.9
38	2021											$3.1
39	Total Rate Base (sum lines 28 thru 38)	n/a	$1.2	$3.8	$6.5	$9.1	$11.6	$14.1	$16.5	$18.9	$21.3	$23.6
40	Revenue Requirements (line 39 * line 27)	n/a	$0.2	$0.7	$1.2	$1.6	$2.1	$2.6	$3.0	$3.4	$3.9	$4.3
41	O&M and Capital Return Savings (line 24 + line 40)	n/a	$0.3	$1.1	$1.6	$2.1	$2.6	$3.0	$3.5	$3.9	$4.4	$4.8

	Material and Supply Procurement	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
		Variance (Preliminary vs Net Benefit Analysis)										
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
42	Material and Supply Procurement	n/a	($3.2)	($4.1)	($5.2)	($6.4)	($7.5)	($8.6)	($9.6)	($10.7)	($11.7)	($12.7)
43	Total Savings Variance	n/a	($3.2)	($4.1)	($5.2)	($6.4)	($7.5)	($8.6)	($9.6)	($10.7)	($11.7)	($12.7)

O. Inventory

Savings Rationale:

In the Net Benefits Study, Northeast Utilities forecast that a combined entity could realize a one-time inventory reduction due to inventory duplication.

Projected Savings:

The Net Benefits Study did not forecast savings associated with this function.

Integration Activities:

The Company is currently conducting a comprehensive review of all warehouses and stocking locations to identify opportunities for efficiencies and cost savings while continuing to meet business needs.

Savings Achieved:

At this time there were no savings associated with this integration initiative.

P. Contract Services

Savings Rationale:

In the Net Benefits Study, the post-merger organization was expected to have opportunities to consolidate and reduce contract services activities through economies of scale and elimination of non-recurring duplicate services, such as tree trimming and construction and similar items.

Projected Savings:

In the Net Benefits Study, projected savings for contract services totaled $2.7 million for 2011, $11 million for 2012 and $11.4 million for 2013.

Integration Activities:

> **Procurement - Contract Rationalization Savings Initiative:** This saving project started the contract consolidation process by focusing on common vendors of NSTAR and Northeast Utilities within the top 80 percent of spend. Through consolidation of vendors and vendor concessions, savings were identified. Ongoing efforts are continuing to identify savings with the smaller common vendors of Northeast Utilities.

Due to the nature of these savings, there is no impact to the ability of the Operating Companies to perform the work necessary to serve customers on a safe and reliable basis.

Savings Achieved

Through December 31, 2013, integration efforts have produced approximately $9.3 million in savings. Annual savings based on integration efforts to date are in the range of $7.3 million.

TABLE P
Contract Services Savings Summary
($ in Millions)

		Original Net Benefit Analysis										
	Contract Services	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
1	Contract Services	$2.7	$11.0	$11.4	$11.6	$11.9	$12.1	$12 3	$12.5	$12.6	$12.8	$13.0
2	Capitalization Rate	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%
3	Total O&M Savings	$0.9	$3.9	$4.0	$4.1	$4.2	$4.2	$4.3	$4.4	$4.4	$4.5	$4.5
4	Total Capitalized Savings	$1.8	$7.2	$7.4	$7.6	$7.7	$7.9	$8.0	$8.1	$8.2	$8.3	$8.4
5	Yearly Depreciation	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%
6	Rate Base Return	18.2%	18 2%	18.2%	18.2%	18.2%	18 2%	18.2%	18.2%	18.2%	18 2%	18.2%
7	2011	$1.8	$1.7	$1.6	$1.6	$1.5	$1.5	$1.4	$1.4	$1.3	$1.3	$1.2
8	2012		$7.2	$6.9	$6.7	$6.4	$6.2	$5.9	$5.7	$5.5	$5.3	$5.1
9	2013			$7.4	$7.1	$6.9	$6.6	$6.4	$6.1	$5.9	$5.7	$5.5
10	2014				$7.6	$7.3	$7.0	$6.8	$6.5	$6.3	$6.0	$5.8
11	2015					$7.7	$7.4	$7.2	$6.9	$6.6	$6.4	$6.2
12	2016						$7 9	$7.6	$7.3	$7.0	$6.8	$6.5
13	2017							$8.0	$7.7	$7.4	$7 1	$6.9
14	2018								$8.1	$7.8	$7 5	$7.2
15	2019									$8.2	$7 9	$7.6
16	2020										$8 3	$8.0
17	2021											$8.4
18	Total Rate Base (sum lines 7 thru 17)	$1.8	$8.9	$15.9	$22.9	$29.8	$36.5	$43.2	$49.7	$56.1	$62.3	$68.5
19	Revenue Requirements (line 18 * line 6)	$0.3	$1.6	$2.9	$4.2	$5.4	$6.6	$7.8	$9.0	$10.2	$11.3	$12.4
20	O&M and Capital Return Savings (line 3 + line 19)	$1.3	$5.5	$6.9	$8.2	$9.6	$10.9	$12.1	$13.4	$14.6	$15.8	$17.0

		Preliminary Results										
	Contract Services	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
21	Inflation Rate			1 6%	2 4%	1 9%	1 9%	1 6%	1 5%	1 4%	1 4%	1 4%
22	Contract Services	n/a	$2.0	$7.3	$7.5	$7.6	$7.7	$7.9	$8.0	$8.1	$8.2	$8.3
23	Capitalization Rate	n/a	62.7%	65.0%	65.0%	65.0%	65 0%	65.0%	65.0%	65.0%	65 0%	65.0%
24	Total O&M Savings	n/a	$0.8	$2.5	$2.6	$2.7	$2.7	$2.8	$2.8	$2.8	$2.9	$2.9
25	Total Capitalized Savings	n/a	$1.3	$4.7	$4.8	$4.9	$5.0	$5.1	$5.2	$5.3	$5.3	$5.4
26	Yearly Depreciation	n/a	3.3%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%
27	Rate Base Return	n/a	17.4%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%
28	2011	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
29	2012		$1.3	$1.2	$1.2	$1.1	$1.1	$1.1	$1.0	$1.0	$0.9	$0.9
30	2013			$4.7	$4.6	$4.4	$4.2	$4.1	$3.9	$3.8	$3.6	$3.5
31	2014				$4.8	$4.7	$4.5	$4.3	$4.2	$4.0	$3.9	$3.7
32	2015					$4.9	$4.8	$4.6	$4.4	$4.2	$4.1	$3.9
33	2016						$5.0	$4.8	$4.7	$4.5	$4.3	$4.2
34	2017							$5.1	$4.9	$4.7	$4.6	$4.4
35	2018								$5.2	$5.0	$4.8	$4.6
36	2019									$5.3	$5.1	$4.9
37	2020										$5.3	$5.1
38	2021											$5.4
39	Total Rate Base (sum lines 28 thru 38)	n/a	$1.3	$6.0	$10.6	$15.1	$19 6	$24.0	$28.3	$32.5	$36 6	$40.7
40	Revenue Requirements (line 39 * line 27)	n/a	$0.2	$1.1	$1.9	$2.7	$3.6	$4.4	$5.1	$5.9	$6.7	$7.4
41	O&M and Capital Return Savings (line 24 + line 40)	n/a	$1.0	$3.6	$4.5	$5.4	$6.3	$7.1	$7.9	$8.7	$9.5	$10.3

		Variance (Preliminary vs Net Benefit Analysis)										
	Contract Services	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
42	Contract Services	n/a	($4.5)	($3.2)	($3.7)	($4.2)	($4.6)	($5.0)	($5.4)	($5.9)	($6.3)	($6.7)
43	Total Savings Variance	n/a	($4.5)	($3.2)	($3.7)	($4.2)	($4.6)	($5.0)	($5.4)	($5.9)	($6.3)	($6.7)

Q. Energy Sourcing

Savings Rationale:

In the Net Benefits Study, Northeast Utilities indicated that, although NSTAR's prior merger enabled the attainment of savings in the energy supply area, the circumstances of the NSTAR/Northeast Utilities merger did not indicate that similar savings would be achievable.

Projected Savings:

In the Net Benefits Study, no cost savings were identified in relation to Energy Sourcing.

Integration Activities:

There has not been any integration activities related to energy sourcing due to the distinct regulatory requirements of the Operating Companies.

Savings Achieved

No savings have been achieved in relation to this functional area.

R. Merger-Related Costs

Estimation of Merger-Related Costs:

The Net Benefits Study recognized that merger-related savings cannot be achieved without expenditures that enable the merger and are necessary to achieve reduced costs of service. These costs fall into two inter-related categories: transaction costs and integration costs. The Net Benefits Study estimated that merger-related transaction and integration costs would total approximately $164 million.

Quantification of Actual Merger-Related Costs:

Table R, below, shows that Northeast Utilities has incurred $113.7 million in merger-related cost through December 31, 2013, with additional costs anticipated in 2014 associated with the IT reorganization. Executive retention and separation payments are excluded from this analysis in accordance with the merger-related settlements.

The Merger-Related Costs shown in Table R are expense items only. Capital investment to implement new information systems or other cost-reduction initiatives are not included , but rather are eligible for rate-base treatment subject to the Department's standard of review for capital projects.

TABLE R
Merger Cost Summary
($ in Millions)

	Merger Cost	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Total
		Preliminary Results													
	Col A	Col B	Col C	Col D	Col E	Col F	Col F	Col G	Col H	Col I	Col J	Col K	Col L	Col L	Col M
	Integration Cost														
1	Separation Costs														
2	Separation Program			$20.5	$10.1										$30.6
3	Executive Separation[(a)]														$0.0
4	Separation Assistance			$0.2											$0.2
5	Retention Costs[(a)]														$0.0
6	System Integration Costs				$5.8	$5.6									$11.4
7	Telecommunication Costs														$0.0
8	Internal/External Communications														$0.0
9	Transition Costs	$0.2	$3.5	$3.2	$2.0										$8.9
	Adjustment to tie to Accounting's total														
	Transaction Costs														
10	Transaction Costs														
11	Bankers Fees	$11.8	$12.1	$24.1											$48.0
12	Lawyers Fees	$4.2	$2.1	$5.4											$11.7
13	Registration	$0.0	$2.1												$2.1
14	Consultants	$0.9	$0.5												$1.4
15	D&O Liability Tail Coverage	$0.0	$0.0												$0.0
16	Regulatory Process Costs														
17	Legal Fees	$1.2	$3.2												$4.4
18	Registration S4	$0.3	$0.0												$0.4
19	Consultants	$0.0	$0.2												$0.2
20	Total Costs	$18.7	$23.7	$53.4	$17.9	$5.6	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$119.4

(a) Excludes executive separation and retention payments per the AG/OCC Merger Settlement Agreement

(b) Non deductible costs have not been grossed up for taxes.

Exhibit No. ES-102

2013 Merger Integration Annual Interim
(MA DPU Docket 14-150)

Eversource Energy Service Company

KEEGAN WERLIN LLP

ATTORNEYS AT LAW

265 FRANKLIN STREET

BOSTON, MASSACHUSETTS 02110 3113

(617) 951 1400

TELECOPIERS:

(617) 951 1354

(617) 951 0586

October 10, 2014

Mark D. Marini, Secretary
Department of Public Utilities
One South Station, 5th Floor
Boston, MA 02110

Re: Northeast Utilities/NSTAR Merger, D.P.U. 10-170 – 2013 Annual Interim Report

Dear Secretary Marini,

On April 4, 2012, the Department of Public Utilities (the "Department") issued its final decision in the above-referenced docket approving the merger of NSTAR and Northeast Utilities. NSTAR/Northeast Utilities, D.P.U. 10-170-B (2012). In the Order, the Department approved a settlement agreement between NSTAR/Northeast Utilities, the Commonwealth of Massachusetts Office of the Attorney General (the "Attorney General"), and the Massachusetts Department of Energy Resources ("DOER") (the "AG-DOER Settlement") The Merger Settlements encompass certain obligations that Northeast Utilities is required to fulfill post-merger for NSTAR Gas Company. This filing fulfills one of those obligations.

Specifically, Article II (15) of the AG-DOER Settlement requires Northeast Utilities to submit an interim report on January 1, 2014 reviewing the previous calendar year's merger integration efforts organized by functional area, including but not limited to merger-related costs incurred, any savings achieved attributable to the merger integration efforts and the impact of the merger integration efforts on the Operating Companies. Article II (15) further establishes that, at least 60 days prior to the filing of the first base-rate proceeding following the Base Rate Freeze Period for NSTAR Gas, the respective Operating Company shall submit a final merger integration report to the Attorney General and to DOER developed utilizing the same manner of information used to compile the Annual Interim Reports.

NSTAR Gas currently expects to file a petition with the Department for a change in base rates under G.L. c. 164, § 94 on or before December 15, 2014. Therefore, in accordance with Article II (15), NSTAR Gas is submitting the 2013 Annual Interim Report on Merger Integration to the Attorney General's office, DOER and the Department.

The 2013 Annual Interim Report on Merger Integration presents: (1) actual merger-related costs for 2010 through 2013; (2) actual merger-related savings through December 31, 2013; and (3) merger-related savings forecast for 2014 through 2022, consistent with the 10-year post-merger savings timeframe projected in the Net Benefit Study. Please note that the figures presented herein differ slightly from the figures reported on January 2, 2014 in the 2013 Annual

Interim Report because the computations presented in the January 2, 2014 Report were based on a combination of actual and projected information for 2013 (see, Page 3, January 2, 2014 Report). The 2013 Annual Interim Report was finalized in June 2014 and is presented in the enclosed document.

In accordance with Article II (15) of the AG-DOER Settlement, the 2014 Annual Interim Report will be submitted on January 2, 2015.

NSTAR Gas Company appreciates the Department's attention to this matter.

Sincerely,

Robert J. Keegan

cc: Jesse Reyes, Office of the Attorney General
Rachel Evans, Department of Energy Resources

Merger Integration
2013 Annual Interim Report

October 10, 2014

Northeast Utilities

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OVERVIEW

Methodology

This Merger Integration Report presents information, by functional area, on the merger related costs incurred and savings achieved in the period between the closing date of the NSTAR/Northeast Utilities merger, April 10, 2012, and December 31, 2013.

The Merger Integration Report is organized to provide merger related savings by functional area consistent with the Net Benefits Study reviewed and approved by the Department in NSTAR/Northeast Utilities, D.P.U. 10 170, 53, 57 58 (2012) (hereinafter, the "Net Benefits Study) In each functional area, Northeast Utilities has identified the principal steps taken to achieve merger related savings. To quantify merger related savings, Northeast Utilities has tracked the savings attributable to merger related integration activities in each functional area.

Differences from the Net Benefits Study: In the Net Benefits Study, the net merger related savings were forecast by year, for a 10 year period, assuming a merger close in 2011. The Merger Savings Summary Table, below, shows that merger related transaction costs were incurred starting in 2010. However, no savings were achieved until the start point of integration, which was the merger closing on April 10, 2012. In addition, this report shows that, although total overall savings are currently projected to exceed the projections encompassed in the Net Benefits Study, the specific areas from which savings have been achieved are different than originally forecast, with some areas yielding greater savings than anticipated and others yielding less. This result is to be expected due to the fact that the savings estimates in the Net Benefit Analysis were derived primarily on the basis of past experience with another merger. Under the circumstances of the NSTAR/Northeast Utilities merger, savings are arising in differing degrees in each functional area.

Computational Inputs: The Merger Savings Summary Table presents: (1) actual merger related costs for 2010 through 2013; (2) actual merger related savings through December 31, 2013; and (3) merger related savings forecast for 2014 through 2022, consistent with the 10 year post merger savings timeframe projected in the Net Benefit Study. The inflation factor used in the original Net Benefits Study is incorporated for 2014 and beyond, capturing the cost increases attributable to inflation that are avoided as a result of the elimination of operating costs.

Interim Results as of December 31, 2013

The Merger Integration Report shows that Northeast Utilities is projecting to exceed the merger savings forecast developed for the Net Benefits Study. Specifically, the Net Benefits Study estimated net merger related savings for the ten years following the merger to be

$784 million on an enterprise wide basis. The Merger Savings Summary Table, below, shows that the cumulative net savings projection is currently calculated to be $876.6 million over the 10 year period following the merger, 2012 through 2022. The projected savings of $876.6 million are net of $119.4 million of merger related costs calculated in Table R, below. A total of $46 million of expected savings was paid to customers up front so that they would realize some of the tangible benefits of the merger upon the merger close, of which a total of $3 million in merger savings was paid out directly to NSTAR Gas customers.

In both Connecticut and Massachusetts, Northeast Utilities entered into merger related settlement agreements designed to ensure net benefits to customers as a result of the merger. A principal term of the settlement agreements was the immediate credit to customers of a portion of the savings expected to result during the settlement periods. The up front payment of $46 million in merger savings to customers caused the need to accelerate the achievement of savings as compared to the Net Benefits Study produced prior to the execution of the settlement agreements. Pursuant to the merger related settlement agreements, executive retention and separation costs are *excluded* from the merger related costs in this Annual Interim Report.

Savings quantifications through December 31, 2013 are presented herein for each functional area covered in the Net Benefits Study, with the original projection from the D.P.U. 10 170 proceeding shown first, followed by a computation of the 2013 Annual Interim savings summary, reflecting results through December 31, 2013.

Table 1
Merger Savings Summary - Rate Case Update
($ in Millions)

		Category	2010	2011	2012*	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022**	Total
1	A	Total Labor Savings	n/a	n/a	$ 8.6	$ 31.6	$ 36.3	$ 38.4	$ 40.5	$ 42.6	$ 44.8	$ 47.0	$ 49.2	$ 51.5	$ 12.9	$ 403.5
2	B	Administrative & General Overhead	n/a	n/a	-	0.6	0.6	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.2	6.6
3	C	Advertising	n/a	n/a	0.6	1.3	1.4	1.4	1.4	1.4	1.5	1.5	1.5	1.5	0.4	14.0
4	D	Benefits	n/a	n/a	-	18.2	20.9	23.7	26.6	29.6	32.7	35.8	39.1	42.4	10.6	279.6
5	E	Insurance	n/a	n/a	1.5	2.2	2.2	2.3	2.3	2.4	2.4	2.4	2.5	2.5	0.6	23.4
6	F	Information Systems	n/a	n/a	0.4	0.4	7.2	13.4	16.2	17.8	18.5	18.8	19.1	19.3	4.8	136.0
7	G	Professional Services	n/a	n/a	0.9	1.4	1.4	1.4	1.5	1.5	1.5	1.5	1.6	1.6	0.4	14.7
8	I	Shareholder Services	n/a	n/a	0.3	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.2	6.8
9	J	Vehicles	n/a	n/a	-	-	-	-	-	-	-	-	-	-	-	-
10	K	Directors Fees	n/a	n/a	0.2	1.2	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.3	0.3	11.8
11	L	Association Dues	n/a	n/a	0.1	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.1	3.9
12	M	Credit Facilities	n/a	n/a	-	-	-	-	-	-	-	-	-	-	-	-
13	N	Materials & Supply Procurement	n/a	n/a	0.3	1.1	1.6	2.1	2.6	3.0	3.5	3.9	4.4	4.8	1.2	28.7
14	P	Contract Services	n/a	n/a	1.0	3.6	4.5	5.4	6.3	7.1	7.9	8.7	9.5	10.3	2.6	67.0
15	R	Merger Related Cost	(18.7)	(23.7)	(53.4)	(17.9)	(5.6)	-	-	-	-	-	-	-	-	(119.4)
16		**Total Net Savings**	$ (18.7)	$ (23.7)	$ (39.4)	$ 44.8	$ 72.9	$ 91.1	$ 100.4	$ 108.6	$ 116.0	$ 123.0	$ 130.1	$ 137.3	$ 34.3	$ 876.6
17		Cummulative Savings	$ (18.7)	$ (42.5)	$ (81.9)	$ (37.1)	$ 35.8	$ 126.8	$ 227.2	$ 335.8	$ 451.8	$ 574.8	$ 704.9	$ 842.3	$ 876.6	
		*9 Months of Savings														
		**3 Months of Savings														

A. Corporate & Administrative Labor

Savings Rationale:

In the Net Benefits Study, Northeast Utilities forecast that reductions in personnel would result from the elimination of duplicative and overlapping Corporate and Administrative functions performed by the two pre merger organizations. Forecasted savings did not include the results of potential re engineering or downsizing opportunities that may be available to each company on a standalone basis.

Projected Savings:

In the Net Benefits Study, projected labor savings totaled $800,000 for 2011, $10.4 million for 2012 and $24.7 million for 2013, for cumulative savings of $35.9 million by December 31, 2013. The cumulative number of staffing reductions through the end of 2013 was forecast at 225 positions, with a cumulative total of 347 positions forecast for 2015.

Integration Activities:

Following the close of the merger, staffing reductions resulted from a reorganization of the Corporate & Administrative function and the elimination of redundant positions. Staffing changes were accelerated from the pace contemplated in the Net Benefits Study, due to the payment of an upfront savings credit to customers upon the merger close and the imposition of base rate freezes. Because the positions eliminated were redundant positions in the new, combined operation, there is no impact to the ability of the Operating Companies to perform the work necessary to serve customers on a safe and reliable basis.

Savings Achieved:

As of December 31, 2013, merger related staffing reductions and attrition accounted for the elimination of 257 positions since the merger close. Merger related reductions are reductions related to NU's merger integration efforts, such as the consolidation of NU and NSTAR duplicate corporate functions or systems. Merger Related job reductions do not include exits from the Company for other reasons such as retirements, resignations, terminations for cause, deaths, probationary terminations, NU's exit from certain competitive businesses or reductions due to normal day to day business and resource needs. In addition, labor savings from attrition is calculated as the difference between the number of employee exits and the number of new hires, as experienced in the respective period within the Northeast Utilities

Service Company and, for former NSTAR employees, in the functional areas encompassed in the Corporate and Administrative group (because NSTAR did not have a service company structure prior to the merger).

These staffing changes have produced total savings through December 31, 2013 of $45.8 million including employee benefits costs and other indirect expenses associated with labor. These savings could not be achieved without the incurrence of certain costs associated with labor reductions. Costs to achieve these savings are included in the computation of Merger Related Costs.

Labor savings are quantified by calculating the actual annual salary and benefits for positions that were merger related reductions and by taking an average salary for positions eliminated through attrition.

Savings associated with anticipated staffing reductions to implement the new IT organizational model are not included in this section as the bulk of the reductions did not occur in 2013. For purposes of the 2013 Annual Interim Report, anticipated future savings associated with the IT reorganization are included in the IT section below.

TABLE A
Corp & Admin Labor Savings Summary
($ in Millions)

		Original Net Benefit Analysis										
	Corp & Admin Labor	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Saving	2020 Savings	2021 Savings
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
1	Employee Reductions	25	100	100	100	22	-	-	-	-	-	-
2	Cummulative Employee Reductions	25	125	225	325	347	347	347	347	347	347	347
3	Corp & Admin Total Labor Savings	$0.8	$10.4	$24.7	$39.8	$50.1	$53.2	$54.6	$56.0	$57.5	$58.9	$60.3
4	Capitalization Rate	16.1%	16.1%	16.1%	16.1%	16.1%	16.1%	16.1%	16.1%	16.1%	16.1%	16.1%
5	Total O&M Savings	$0.7	$8.7	$20.7	$33.4	$42.0	$44.6	$45.9	$47.0	$48.2	$49.4	$50.7
6	Total Capitalized Savings	$0.1	$1.7	$4.0	$6.4	$8.0	$8.5	$8.8	$9.0	$9.2	$9.5	$9.7
7	Yearly Depreciation	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%
8	Rate Base Return	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%
9	2011	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
10	2012		$1.7	$1.6	$1.5	$1.5	$1.4	$1.4	$1.3	$1.3	$1.2	$1.2
11	2013			$4.0	$3.8	$3.7	$3.5	$3.41	$3.3	$3.2	$3.0	$2.9
12	2014				$6.4	$6.2	$5.9	$5.7	$5.5	$5.3	$5.1	$4.9
13	2015					$8.0	$7.7	$7.5	$7.2	$6.9	$6.7	$6.4
14	2016						$8.5	$8.2	$7.9	$7.6	$7.3	$7.1
15	2017							$8.8	$8.4	$8.1	$7.8	$7.5
16	2018								$9.0	$8.7	$8.3	$8.0
17	2019									$9.2	$8.9	$8.6
18	2020										$9.5	$9.1
19	2021											$9.7
20	Total Rate Base (sum lines 9 thru 19)	$0.1	$1.8	$5.7	$11.9	$19.5	$27.3	$35.0	$42.7	$50.4	$58.0	$65.5
21	Revenue Requirements (line 20 * line 8)	$0.0	$0.3	$1.0	$2.2	$3.5	$5.0	$6.4	$7.8	$9.1	$10.5	$11.9
22	O&M and Capital Return Savings (line 5 + line 21)	$0.7	$9.0	$21.8	$35.6	$45.6	$49.6	$52.2	$54.8	$57.4	$60.0	$62.5

		Preliminary Results										
	Corp & Admin Labor	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Saving	2020 Savings	2021 Savings
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
23	Inflation Rate			2.2%	2.5%	2.9%	2.9%	2.9%	2.9%	2.9%	2.9%	2.9%
24	Employee Reductions	-	200	57	-	-	-	-	-	-	-	-
25	Cummulative Employee Reductions	0	200	257	257	257	257	257	257	257	257	257
26	Corp & Admin Total Labor Savings	n/a	$9.7	$36.1	$40.4	$41.5	$42.7	$43.9	$45.2	$46.5	$47.9	$49.2
27	Capitalization Rate	n/a	13.4%	16.1%	16.1%	16.1%	16.1%	16.1%	16.1%	16.1%	16.1%	16.1%
28	Total O&M Savings	n/a	$8.4	$30.3	$33.9	$34.9	$35.9	$36.9	$38.0	$39.1	$40.2	$41.3
29	Total Capitalized Savings	n/a	$1.3	$5.8	$6.5	$6.7	$6.9	$7.1	$7.3	$7.5	$7.7	$7.9
30	Yearly Depreciation	n/a	3.3%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%
31	Rate Base Return	n/a	17.4%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%
32	2011	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
33	2012		$1.3	$1.3	$1.2	$1.2	$1.1	$1.1	$1.0	$1.0	$1.0	$0.9
34	2013			$5.8	$5.6	$5.4	$5.2	$4.99	$4.8	$4.6	$4.5	$4.3
35	2014				$6.5	$6.2	$6.0	$5.8	$5.6	$5.4	$5.2	$5.0
36	2015					$6.7	$6.4	$6.2	$6.0	$5.7	$5.5	$5.3
37	2016						$6.9	$6.6	$6.4	$6.1	$5.9	$5.7
38	2017							$7.1	$6.8	$6.5	$6.3	$6.1
39	2018								$7.3	$7.0	$6.7	$6.5
40	2019									$7.5	$7.2	$6.9
41	2020										$7.7	$7.4
42	2021											$7.9
43	Total Rate Base (sum lines 32 thru 42)	n/a	$1.3	$7.1	$13.3	$19.4	$25.6	$31.7	$37.8	$43.8	$49.9	$56.0
44	Revenue Requirements (line 43 * line 31)	n/a	$0.2	$1.3	$2.4	$3.5	$4.6	$5.8	$6.9	$8.0	$9.1	$10.2
45	O&M and Capital Return Savings (line 28 + line 44)	n/a	$8.6	$31.6	$36.3	$38.4	$40.5	$42.6	$44.8	$47.0	$49.2	$51.5

		Variance (Preliminary Results vs Net Benefit Analysis)										
	Corp & Admin Labor	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Saving	2020 Savings	2021 Savings
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
46	Corp & Admin Total Labor Savings Variance (line 45 - line 22)	n/a	($0.4)	$9.8	$0.7	($7.2)	($9.1)	($9.6)	($10.0)	($10.4)	($10.7)	($11.1)

B. Administrative & General Overhead

Savings Rationale:

Administrative and general overhead costs include office supplies, telephone expenses, employee business expenses and other miscellaneous costs. Administrative and general overhead was anticipated to decrease as corporate personnel are reduced.

Projected Savings:

In the Net Benefits Study, projected administrative and general overhead savings totaled $300,000 for 2012 and $700,000 for 2013, for total savings of $1 million by December 31, 2013.

Integration Activities:

Following the close of the merger, staffing reductions resulted from a reorganization of the Corporate & Administrative function and the elimination of redundant positions. Initiatives include consolidated procurement for office supplies and paper across the combined Company resulting in improved pricing and rebates. Additionally, the Company was able to realize savings on printer and telephone cost. Due to the nature of these savings, there is no impact to the ability of the Operating Companies to perform the work necessary to serve customers on a safe and reliable basis.

Savings Achieved:

Through December 31, 2013, savings of approximately $700,000 have resulted from the creation of purchasing leverage due to the larger Northeast Utilities footprint, which allowed for negotiation of new reduced contracts for office supplies, paper supply, printer and telephone support. Annual savings based on integration efforts to date are in the range of $700,000.

TABLE B
Admin & General Savings Summary
($ in Millions)

	Admin & General Overhead	**Original Net Benefit Analysis** 2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
1	Total Savings	$0.0	$0.3	$0.7	$1.1	$1.4	$1.5	$1.5	$1.5	$1.6	$1.6	$1.6
2	Capitalization Rate	16.1%	16.1%	16.1%	16.1%	16.1%	16.1%	16.1%	16.1%	16.1%	16.1%	16.1%
3	Total O&M Savings	$0.0	$0.2	$0.6	$1.0	$1.2	$1.3	$1.3	$1.3	$1.3	$1.3	$1.3
4	Total Capitalized Savings	$0.0	$0.0	$0.1	$0.2	$0.2	$0.2	$0.2	$0.2	$0.3	$0.3	$0.3
5	Yearly Depreciation	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%
6	Rate Base Return	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%
7	2011	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
8	2012		$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
9	2013			$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
10	2014				$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.1	$0.1
11	2015					$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2
12	2016						$0.2	$0.2	$0.2	$0.2	$0.2	$0.2
13	2017							$0.2	$0.2	$0.2	$0.2	$0.2
14	2018								$0.2	$0.2	$0.2	$0.2
15	2019									$0.3	$0.2	$0.2
16	2020										$0.3	$0.2
17	2021											$0.3
18	Total Rate Base (sum lines 7 thru 17)	$0.0	$0.1	$0.2	$0.3	$0.6	$0.8	$1.0	$1.2	$1.4	$1.6	$1.8
19	Revenue Requirements (line 18 * line 6)	$0.0	$0.0	$0.0	$0.1	$0.1	$0.1	$0.2	$0.2	$0.3	$0.3	$0.3
20	O&M and Capital Return Savings (line 3 + line 19)	$0.0	$0.3	$0.6	$1.0	$1.3	$1.4	$1.5	$1.5	$1.6	$1.6	$1.7

		Preliminary Results										
	Admin & General Overhead	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
21	Inflation Rate			1 6%	2 4%	1 9%	1 9%	1 6%	1 5%	1 4%	1 4%	1 4%
22	Total Savings	n/a	$0.0	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7	$0.8	$0.8	$0.8
23	Capitalization Rate	n/a	13.4%	16.1%	16.1%	16.1%	16.1%	16.1%	16.1%	16.1%	16.1%	16.1%
24	Total O&M Savings	n/a	$0.0	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6	$0.7
25	Total Capitalized Savings	n/a	$0.0	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
26	Yearly Depreciation	n/a	3.3%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%
27	Rate Base Return	n/a	17.4%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%
28												
29	2011	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
30	2012		$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
31	2013			$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
32	2014				$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
33	2015					$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
34	2016						$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
35	2017							$0.1	$0.1	$0.1	$0.1	$0.1
36	2018								$0.1	$0.1	$0.1	$0.1
37	2019									$0.1	$0.1	$0.1
38	2020										$0.1	$0.1
39	2021											$0.1
40	Total Rate Base (sum lines 29 thru 39)	n/a	$0.0	$0.1	$0.2	$0.3	$0.4	$0.5	$0.6	$0.7	$0.8	$0.9
41	Revenue Requirements (line 40 * line 27)	n/a	$0.0	$0.0	$0.0	$0.1	$0.1	$0.1	$0.1	$0.1	$0.2	$0.2
42	O&M and Capital Return Savings (line 24 + line 41)	n/a	$0.0	$0.6	$0.6	$0.7	$0.7	$0.7	$0.7	$0.8	$0.8	$0.8

		Variance (Preliminary vs Net Benefit Analysis)										
	Admin & General Overhead	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
43	Admin & General Overhead	n/a	($0.3)	($0.0)	($0.4)	($0.6)	($0.7)	($0.7)	($0.8)	($0.8)	($0.8)	($0.9)
44	Total Savings	n/a	($0.3)	($0.0)	($0.4)	($0.6)	($0.7)	($0.7)	($0.8)	($0.8)	($0.8)	($0.9)

C. Advertising

Savings Rationale:

In the Net Benefits Study, Northeast Utilities forecast that the integration of corporate public relations programs would eliminate the need for duplicative advertising related design and production, and would reduce advertising fees.

Projected Savings:

In the Net Benefits Study, projected advertising savings totaled $200,000 for 2011, $700,000 for 2012 and $800,000 for 2013, for total savings of $1.7 million by December 31, 2013.

Integration Activities:

Following the close of the merger, Northeast Utilities cancelled the retainer for two advertising consulting agencies, whose services were not necessary under the combined company (savings of $600,000). Northeast Utilities also consolidated its media monitoring services and press release distribution account (savings of $160,000). Northeast Utilities reviewed its trade show participation, and as a combined company, was able to reduce the frequency of its participation (savings of $300,000). Savings were also achieved through (1) consolidation of corporate social responsibility reports and the elimination of paper production (savings of $177,000); (2) consolidation of existing NSTAR and NU Copyright Clearance Center contracts into one contract (savings of $2,000); (3) consolidation of the NSTAR and NU newsletters and collateral development documents from 45 publications to less than 10 (savings of $100,000). Due to the nature of these savings, there is no impact to the ability of the Operating Companies to perform the work necessary to serve customers on a safe and reliable basis.

Savings Achieved:

Through December 31, 2013, savings of approximately $2.0 million were achieved through integration and consolidation. Annual savings based on integration efforts to date are in the range of $1.3 million.

TABLE C
Advertising Savings Summary
($ in Millions)

	Advertising	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
		Original Net Benefit Analysis										
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
1	Advertising	$0.2	$0.7	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.9	$0.9
2	Total Savings	$0.2	$0.7	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.9	$0.9

	Advertising	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
		Preliminary Results										
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
3	Inflation Rate			1.6%	2.4%	1.9%	1.9%	1.6%	1.5%	1.4%	1.4%	1.4%
4	Advertising	n/a	$0.6	$1.3	$1.4	$1.4	$1.4	$1.4	$1.5	$1.5	$1.5	$1.5
5	Total Savings	n/a	$0.6	$1.3	$1.4	$1.4	$1.4	$1.4	$1.5	$1.5	$1.5	$1.5

	Advertising	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
		Variance (Preliminary vs. Net Benefit Analysis)										
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
6	Advertising	n/a	($0.1)	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6	$0.7	$0.7
7	Total Savings Variance	n/a	($0.1)	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6	$0.7	$0.7

D. Benefits Administration

Savings Rationale:

In the Net Benefits Study, Northeast Utilities forecast that cost savings in benefits administration could occur in several areas, primarily through increased purchasing power in negotiating third party administration fees and integration of benefit plans.

Projected Savings:

In the Net Benefits Study, projected benefits administration savings totaled $1.4 million for 2011, $5.8 million for 2012 and $6.1 million for 2013, for total annual savings of $13.3 million by December 31, 2013.

Integration Activities:

Northeast Utilities has undertaken several activities to integrate and align the benefit plans for employees. The Company first performed a comprehensive review of the legacy benefit plans enabling plan consolidation. Northeast Utilities also conducted RFPs for active and retiree health and welfare programs. Through this competitive bidding process, significant value was achieved in the following awards:

Provider	Coverage Type
Cigna	Medical and Prescription
Express Scripts	Prescription Drugs
Delta Dental	Dental
VSP	Vision
Minnesota Life	Life Insurance
KGA	Employee Assistance Program

Effective January 1, 2013, new health and welfare benefits were implemented for all non represented employees. During 2013, as collective bargaining unit contracts expired, new health plans were successfully negotiated with the largest unions. By January 1, 2014, nearly all NU system employees will have the same standard health plan designs. In addition, effective April 2, 2013, retirement benefits to new Northeast Utilities employees will take the form of an enhanced defined contribution plan, instead of a defined benefit plan. This will reduce pension liabilities and cost volatility over time.

Due to the nature of these savings, there is no impact to the ability of the Operating Companies to perform the work necessary to serve customers on a safe and reliable basis.

Savings Achieved:

Through December 31, 2013, savings estimated at $27.2 million were achieved through integration and consolidation**.** Annual savings based on integration efforts to date are in the range of $27.2 million.

TABLE D
Benefits Administration Savings Summary
($ in Millions)

		Original Net Benefit Analysis										
	Benefits Administration	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
1	Total Benefits Savings	$1.4	$5.8	$6.1	$6.4	$6.7	$7.0	$7.3	$7.7	$8.0	$8.4	$8.8
2	Capitalization Rate	40.6%	40.6%	40.6%	40.6%	40.6%	40.6%	40.6%	40.6%	40.6%	40.6%	40.6%
3	Total O&M Savings	$0.8	$3.4	$3.6	$3.8	$4.0	$4.1	$4.3	$4.6	$4.8	$5.0	$5.2
4	Total Capitalized Savings	$0.6	$2.3	$2.5	$2.6	$2.7	$2.8	$3.0	$3.1	$3.3	$3.4	$3.6
5	Yearly Depreciation	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%
6	Rate Base Return	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%
7	2011	$0.6	$0.5	$0.5	$0.5	$0.5	$0.5	$0.4	$0.4	$0.4	$0.4	$0.4
8	2012		$2.3	$2.3	$2.2	$2.1	$2.0	$1.9	$1.9	$1.8	$1.7	$1.7
9	2013			$2.5	$2.4	$2.3	$2.2	$2.1	$2.1	$2.0	$1.9	$1.8
10	2014				$2.6	$2.5	$2.4	$2.3	$2.2	$2.1	$2.1	$2.0
11	2015					$2.7	$2.6	$2.5	$2.4	$2.3	$2.2	$2.2
12	2016						$2.8	$2.7	$2.6	$2.5	$2.4	$2.3
13	2017							$3.0	$2.9	$2.8	$2.7	$2.6
14	2018								$3.1	$3.0	$2.9	$2.8
15	2019									$3.3	$3.1	$3.0
16	2020										$3.4	$3.3
17	2021											$3.6
18	Total Rate Base (sum lines 8 thru 17)	$0.6	$2.9	$5.3	$7.6	$10.1	$12.5	$15.0	$17.6	$20.2	$22.9	$25.6
19	Revenue Requirements (line 17 * line 7)	$0.1	$0.5	$1.0	$1.4	$1.8	$2.3	$2.7	$3.2	$3.7	$4.2	$4.7
20	O&M and Capital Return Savings (line 3 + line 19)	$0.9	$4.0	$4.6	$5.2	$5.8	$6.4	$7.1	$7.8	$8.4	$9.2	$9.9

		Preliminary Results										
	Benefits Administration	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
21	Inflation Rate			2.20%	4.46%	4.47%	4.77%	4.85%	4.81%	4.80%	4.81%	4.84%
22	Total Benefits Savings	n/a	$0.0	$27.2	$28.4	$29.7	$31.1	$32.6	$34.2	$35.8	$37.5	$39.4
23	Capitalization Rate	n/a	34.8%	40.6%	40.6%	40.6%	40.6%	40.6%	40.6%	40.6%	40.6%	40.6%
24	Total O&M Savings	n/a	$0.0	$16.2	$16.9	$17.6	$18.5	$19.4	$20.3	$21.3	$22.3	$23.4
25	Total Capitalized Savings	n/a	$0.0	$11.0	$11.5	$12.1	$12.6	$13.2	$13.9	$14.5	$15.2	$16.0
26	Yearly Depreciation	n/a	3.3%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%
27	Rate Base Return	n/a	17.4%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%
28	2011	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
29	2012		$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
30	2013			$11.0	$10.6	$10.2	$9.9	$9.5	$9.2	$8.8	$8.5	$8.2
31	2014				$11.5	$11.1	$10.7	$10.3	$9.9	$9.6	$9.2	$8.9
32	2015					$12.1	$11.6	$11.2	$10.8	$10.4	$10.0	$9.6
33	2016						$12.6	$12.2	$11.7	$11.3	$10.9	$10.5
34	2017							$13.2	$12.8	$12.3	$11.8	$11.4
35	2018								$13.9	$13.4	$12.9	$12.4
36	2019									$14.5	$14.0	$13.5
37	2020										$15.2	$14.7
38	2021											$16.0
39	Total Rate Base (sum lines 29 thru 38)	n/a	$0.0	$11.0	$22.2	$33.4	$44.8	$56.4	$68.2	$80.2	$92.5	$105.1
40	Revenue Requirements (line 38 * line 28)	n/a	$0.0	$2.0	$4.0	$6.1	$8.1	$10.2	$12.4	$14.6	$16.8	$19.1
41	O&M and Capital Return Savings (line 24 + line 40)	n/a	$0.0	$18.2	$20.9	$23.7	$26.6	$29.6	$32.7	$35.8	$39.1	$42.4

		Variance (Preliminary vs Net Benefit Analysis)										
	Benefits Administration	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
42	Benefits Administration	n/a	($4.0)	$13.6	$15.7	$17.9	$20.2	$22.5	$24.9	$27.4	$29.9	$32.5
43	Total Savings Variance	n/a	($4.0)	$13.6	$15.7	$17.9	$20.2	$22.5	$24.9	$27.4	$29.9	$32.5

E. Insurance

Savings Rationale:

In the Net Benefits Study, Northeast Utilities forecasted the combined company would be able to extend its coverage with its carriers over a larger asset and loss experience base, which would reduce overall cost. Combination of the insurance programs would also provide an opportunity to reassess needed coverage levels and related deductibles based on the loss experience and risk profile of the combined company.

Projected Savings:

In the Net Benefits Study, projected insurance savings totaled $500,000 for 2011, $2,200,000 for 2012 and $2,200,000 for 2013, for total savings of $4.9 million by December 31, 2013.

Integration Activities:

Following the merger close, Northeast Utilities reviewed existing insurance policies and coverage and combined the individual legacy company policies as those policies expired, resulting in better pricing for the combined company than on a stand alone basis. Due to the nature of these savings, there is no impact to the ability of the Operating Companies to perform the work necessary to serve customers on a safe and reliable basis.

Savings Achieved:

Through December 31, 2013, cumulative savings of approximately $3.7 million were achieved through integration and consolidation. Annual savings based on integration efforts to date are in the range of $2.2 million.

TABLE E
Insurance Savings Summary
($ in Millions)

Original Net Benefit Analysis

	Insurance	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
1	Insurance	$0.5	$2.2	$2.2	$2.3	$2.3	$2.4	$2.4	$2.4	$2.5	$2.5	$2.5
2	Total Savings	$0.5	$2.2	$2.2	$2.3	$2.3	$2.4	$2.4	$2.4	$2.5	$2.5	$2.5

Preliminary Results

	Insurance	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
3	Inflation Rate			1.6%	2.4%	1.9%	1.9%	1.6%	1.5%	1.4%	1.4%	1.4%
4	Insurance	n/a	$1.5	$2.2	$2.2	$2.3	$2.3	$2.4	$2.4	$2.4	$2.5	$2.5
5	Total Savings	n/a	$1.5	$2.2	$2.2	$2.3	$2.3	$2.4	$2.4	$2.4	$2.5	$2.5

Variance (Preliminary vs Net Benefit Analysis)

	Insurance	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
6	Insurance	n/a	($0.7)	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)
7	Total Savings Variance	n/a	($0.7)	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)

F. Information Systems

Savings Rationale:

In the Net Benefits Study, IT related capital savings were expected to result from the avoidance and elimination of duplicate or unnecessary system development expenditures and the creation of a common IT infrastructure and architecture across the combined company. In addition, the combined entity was expected to avoid system development costs. Also in the Nets Benefit Study, IT related O&M cost savings were expected as a result of the avoidance of leasing desktop computers because of the reduced number of positions requiring workstations. Savings were expected to occur due to the elimination of software and hardware leases, and associated maintenance, resulting from the migration to a common operating platform.

Projected Savings:

In the Net Benefits Study, projected IT savings totaled $200,000 for 2011, $2,300,000 for 2012 and $5,400,000 for 2013, for total savings of $7.9 million by December 31, 2013.

Integration Activities:

Northeast Utilities has consolidated its Corporate Income Tax Return Reporting Systems and Claims Management Systems. The Company has also upgraded and integrated the existing PowerPlant installations and implemented one budgeting system across the operating companies. In addition, Northeast Utilities has consolidated email systems**,** eliminating issues with email compatibility and calendaring and reducing email support cost. Northeast Utilities has also addressed an immediate need to share applications among the operating companies by expanding cross company application sharing environments in both Westwood, MA & Windsor, CT. The cost of these initiatives is included as Merger Related Costs, below.

In October 2013, Northeast Utilities announced an initiative involving the reorganization of the Information Technology department. At this stage Northeast Utilities has incurred costs in furtherance of this initiative with savings anticipated to begin in mid 2014 and future years. A preliminary estimate of the net labor savings is included in this section and the associated costs are included in the Merger Related Cost section. This estimate is preliminary and will be refined in future interim reports. The estimate includes labor savings from an anticipated reduction in NU staff; estimated contracted savings from elimination of current contractors and the estimated cost of new contractors. The net amount is included in the O&M savings amount. This total will be further refined as actual savings and costs are known.

The reorganization of the IT Organization will have no impact on the ability of the Operating Companies to perform the work necessary to serve customers on a safe and reliable basis under routine conditions and under storm conditions.

Savings Achieved:

As of December 31, 2013, O&M savings of approximately $800,000 were achieved through integration and consolidation. Additional net savings are anticipated to result in 2014 as the IT reorganization is implemented.

TABLE F
IT O&M & Capital Savings Summary
($ in Millions)

	IT Savings	Original Net Benefit Analysis										
		2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
1	Total O&M Savings	$0 1	$0 9	$2 3	$3 6	$4 6	$4 9	$5 0	$5 1	$5 2	$5 4	$5 5
2	Total Capitalized Savings	$0 1	$1 3	$3 1	$5 0	$6 3	$6 7	$6 9	$7 1	$7 2	$7 4	$7 6
3	O&M and Capital Return Savings (line 1 + line 2)	$0 2	$2 3	$5 4	$8 7	$10 9	$11 6	$11 9	$12 2	$12 5	$12 8	$13 1

	IT Savings	Preliminary Results										
		2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
4	Inflation Rate			1 6%	2 4%	1 9%	1 9%	1 6%	1 5%	1 4%	1 4%	1 4%
5	Total O&M Savings	n/a	$0 4	$0 4	$7 2	$13 4	$16 2	$17 8	$18 5	$18 8	$19 1	$19 3
6	Total Capitalized Savings	n/a	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0
7	Yearly Depreciation	n/a	3 3%	3 7%	3 7%	3 7%	3 7%	3 7%	3 7%	3 7%	3 7%	3 7%
8	Rate Base Return	n/a	17 4%	18 2%	18 2%	18 2%	18 2%	18 2%	18 2%	18 2%	18 2%	18 2%
9	2011	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
10	2012		$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0
11	2013			$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0
12	2014				$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0
13	2015					$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0
14	2016						$0 0	$0 0	$0 0	$0 0	$0 0	$0 0
15	2017							$0 0	$0 0	$0 0	$0 0	$0 0
16	2018								$0 0	$0 0	$0 0	$0 0
17	2019									$0 0	$0 0	$0 0
18	2020										$0 0	$0 0
19	2021											$0 0
20	Total Rate Base (sum lines 9 thru 19)	n/a	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0
21	Revenue Requirements (line 20 * line 8)	n/a	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0
22	O&M and Capital Return Savings (line 5 + line 21)	n/a	$0 4	$0 4	$7 2	$13 4	$16 2	$17 8	$18 5	$18 8	$19 1	$19 3

	IT Savings	Variance (Preliminary vs Net Benefit Analysis)										
		2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
23	IT O&M & Capital	n/a	($1 8)	($5 0)	($1 4)	$2 5	$4 6	$5 9	$6 4	$6 3	$6 3	$6 2
24	Total Savings Variance	n/a	($1 8)	($5 0)	($1 4)	$2 5	$4 6	$5 9	$6 4	$6 3	$6 3	$6 2

G. Professional Services

Rationale for Savings:

In the Net Benefits Study, Northeast Utilities projected that it would work to consolidate and reduce professional services activities through economies of scope and elimination of non recurring duplicate services and increased utilization of a broader skill base. It was also contemplated that audit and legal services costs could be reduced to eliminate duplication.

Projected Savings:

In the Net Benefits Study, projected professional services savings totaled $700,000 for 2011, $3,000,000 for 2012 and $3,000,000 for 2013, for total savings of $6.7 million by December 31, 2013.

Integration Activities:

P-Card/T&E Card Consolidation: This savings project consolidated the existing corporate procurement credit cards with a single vendor, resulting in increased volume rebates. The new corporate procurement cards were fully rolled out to Northeast Utilities employees in the second half of 2013 (savings of $130,000 annually).

Staff Augmentation Contract Consolidation (Guidant): This savings project is based on consolidating the management of staff augmentation into a single third party vendor to leverage volume and reduce administration/management fees. Northeast Utilities is currently tracking ahead of projected savings by moving from Zempleo to Guidant for payroll services (savings of $100,000 annually).

External Auditor Consolidation: Northeast Utilities terminated the duplicative relationship with the NSTAR auditors (PwC) by keeping the existing the auditors (Deloitte) (savings of approximately $700,000 annually).

Eliminate Westlaw Contract: Northeast Utilities integrated the NSTAR Westlaw service into the Northeast Utilities service at no additional cost (savings of $65,000 annually).

Eliminate Nixon Peabody Lease: Northeast Utilities cancelled the lease for office space at Nixon Peabody in Boston, MA, as the space is no longer needed (savings of $60,000 in annually)**.**

Eliminate Towers Watson NSTAR Fair Values Fees: Savings were derived by avoiding the duplicative engagement of Towers Watson to calculate performance share compensation (savings of $15,000 annually).

Financial Reporting Integration: This effort involved insourcing XBRL/Edgarization 10 K filing requirements. Northeast Utilities completes this financial reporting process without external providers. The savings are derived from terminating a third party contract which was providing these services for NSTAR (savings of $120,000 annually).

Consolidation of 3rd Party Call Center Contracts: Post merger, Northeast Utilities was able to consolidate the 3rd party call center contract under one contract (savings of $120,000 annually).

Due to the nature of these savings, there is no impact to the ability of the Operating Companies to perform the work necessary to serve customers on a safe and reliable basis.

Savings Achieved:

Through December 31, 2013, savings of approximately $2.3 million were achieved through integration and consolidation. Annual savings based on integration efforts to date are in the range of $1.4 million.

TABLE G
Professional Services Savings Summary
($ in Millions)

Original Net Benefit Analysis

	Professional Services	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
1	Professional Services	0.7	3.0	3.0	3.1	3.2	3.2	3.3	3.3	3.4	3.4	3.5
2	Total Savings	$0.7	$3.0	$3.0	$3.1	$3.2	$3.2	$3.3	$3.3	$3.4	$3.4	$3.5

Preliminary Results

	Professional Services	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
3	Inflation Rate			1.6%	2.4%	1.9%	1.9%	1.6%	1.5%	1.4%	1.4%	1.4%
4	Professional Services	n/a	0.9	1.4	1.4	1.4	1.5	1.5	1.5	1.5	1.6	1.6
5	Total Savings	n/a	$0.9	$1.4	$1.4	$1.4	$1.5	$1.5	$1.5	$1.5	$1.6	$1.6

Variance (Preliminary vs Net Benefit Analysis)

	Professional Services	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
6	Professional Services	n/a	(2.1)	(1.7)	(1.7)	(1.7)	(1.8)	(1.8)	(1.8)	(1.8)	(1.9)	(1.9)
7	Total Savings Variance	n/a	($2.1)	($1.7)	($1.7)	($1.7)	($1.8)	($1.8)	($1.8)	($1.8)	($1.9)	($1.9)

H. Facilities

Savings Rationale:

In the Net Benefits Study, Northeast Utilities indicated that, normally, a post merger entity will consolidate selected facilities, including service centers, garages, data centers, meter shops, warehousing and other corporate facilities. However, due to the geographic disparity of the post merger operating companies, facilities integration was not anticipated.

Projected Savings:

The Net Benefits Study did not contemplate any savings associated with facilities consolidation.

Integration Activities:

Since the merger, Northeast Utilities has undertaken a facilities review across its entire service territory to ensure that its current facilities sufficiently meet operational needs. This initiative follows the merger, but is not tied directly to integration activities.

Currently, Northeast Utilities operates 102 work sites (78 owned, 24 leased), encompassing 161 buildings with approximately five million square feet of space. Following the merger, NU's integration team performed a comprehensive facilities review, assessing all work centers, service centers, line shops, warehouses, corporate offices and call centers. In addition to geographic distribution, occupancy levels and functionality, the integration team reviewed the future capital needs and investment required at each facility for maintenance and enhancements. As a result of this comprehensive facilities review, NU is expecting to implement certain facilities changes in the next 15 months.

Savings Achieved:
No savings were achieved through December 31, 2013 associated with facilities.

I. Shareholder Services

Rationale for Savings:

Cost savings are expected to result from the elimination of duplicative shareholder related activities, such as conducting the annual shareholder meeting, proxy services and payment of stock exchange fees. The combination will reduce incremental costs per additional shareholder due to economies of scale.

Projected Savings:

In the Net Benefits Study, projected shareholder services savings totaled $100,000 for 2011, $500,000 for 2012 and $500,000 for 2013, for total savings of $1.1 million by December 31, 2013.

Integration Activities:

Transfer Agent Services: NU issued a Request for Proposals (RFP) for the provision of transfer agent services. The transfer agent's responsibilities include maintaining the company's shareholder records, distributing quarterly dividend checks and reinvestment plan statements for the registered shareholder base as well as tax information related to dividends and the sale of shares. It also includes annual distribution of proxy materials to registered shareholders in advance of the Company's annual meeting of shareholders and compliance with escheatment laws. Computershare was chosen to serve as the Company's transfer agent under a three year contact. Additionally, NU amended various provisions of the NU dividend reinvestment plan (DRP) to mirror the legacy NSTAR dividend reinvestment plan. As a result of this action, the Company was able to avoid the cost and inconvenience to participants of re registering nearly 10,000 NSTAR registered holders in the NU DRP. By mirroring the NSTAR plan, the Company was also able to lower reinvestment fees considerably for legacy NU shareholders.

Thomson Reuters Investor Relations (IR) Services: Prior to the merger, NU and NSTAR had contracts in place for various Investor Relations services including management of an Investor Relations website at NSTAR, with Thomson Reuters. Thomson Reuters continues to provide more abbreviated services under a new consolidated three year contract. A large portion of these costs are covered by a subsidy from the New York Stock Exchange, Inc. (NYSE) that has historically been available to NU.

IPREO: Prior to the merger, NSTAR had retained IPREO, a market surveillance firm, to assist with its ongoing Investor Relations program. IPREO's services continue with NU but at a reduced overall cost as its services qualify under the aforementioned subsidy from the NYSE.

Proxy Solicitor: Prior to the merger, NU and NSTAR each retained a proxy solicitor to provide services related to each company's annual meeting of shareholders. An RFP was issued and four companies provided bids. After a comprehensive review of the bids, AST Phoenix Advisory Partners was chosen to provide proxy services for the combined company at a cost that is less than the sum of what each company paid for these services in the past.

Annual Meeting, Proxy Mailings, Broadridge: In conjunction with the annual meeting of shareholders, NU and NSTAR distributed proxy materials to its shareholders through an independent agent, Broadridge. The fee consists primarily of postage and related costs to distribute proxy materials. The fee is also a function of the number of accounts managed by Broadridge. The number of accounts now managed by Broadridge after the merger's completion is less than the sum of the NU and NSTAR accounts prior to the merger.

Annual Report to Shareholders: Prior to the merger, NU and NSTAR produced an Annual Report to Shareholders for distribution to their shareholders in advance of their annual meetings. After the merger, the "combined NU" produced an annual report at a cost that was significantly less than the sum of what it cost each company to produce its own 2011 annual report. NU also utilized a "Notice & Access" approach in the distribution of its 2012 report. This approach offers shareholders the opportunity to view its proxy materials on the Internet instead of receiving a copy in the mail and reduces both printing and mailing costs.

Rating Agencies: Northeast Utilities negotiated lower rating agency fees due to the larger size of the merged company.

Due to the nature of these savings, there is no impact to the ability of the Operating Companies to perform the work necessary to serve customers on a safe and reliable basis.

Savings Achieved:
Through December 31, 2013, savings of approximately $900,000 were achieved through integration and consolidation. Annual savings based on integration efforts to date are in the range of $600,000.

TABLE I
Shareholder Services Savings Summary
($ in Millions)

		Original Net Benefit Analysis										
	Shareholder Services	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
1	Shareholder Services	0.1	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
2	Total Savings	$0.1	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5

		Preliminary Results										
	Shareholder Services	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
3	Inflation Rate			1.6%	2.4%	1.9%	1.9%	1.6%	1.5%	1.4%	1.4%	1.4%
4	Shareholder Services	n/a	0.3	0.6	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7
5	Total	n/a	$0.3	$0.6	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7

		Variance (Preliminary vs Net Benefit Analysis)										
	Shareholder Services	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
6	Shareholder Services	n/a	(0.2)	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
7	Total Savings Variance	n/a	($0.2)	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2

J. Vehicles

Savings Rationale:

Prior to the merger, Northeast Utilities contemplated that the combined company will reduce the total number of corporate A&G employees. As a result of the reduction in the number of employees, the new company will use fewer passenger cars. Savings will be realized through reduced total operating costs for passenger cars. Reduced reimbursable mileage is reflected in Section D: Administrative and General Overhead.

Projected Savings:

In the Net Benefits Study, there were modest amounts of projected vehicle cost savings for 2011, 2012 and 2013.

Integration Activities:

Vehicle savings achieved through December 31, 2013 were modest as anticipated and are not individually quantified as yet.

TABLE J
Vehicles Savings Summary
($ in Millions)

	Vehicles	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
		Original Net Benefit Analysis										
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
1	Total Transportation Cost	$0.0	$0.0	$0.0	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
2	Total	$0.0	$0.0	$0.0	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1

	Vehicles	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
		Preliminary Results										
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
3	Inflation Rate			1.6%	2.4%	1.9%	1.9%	1.6%	1.5%	1.4%	1.4%	1.4%
4	Total Transportation Cost	n/a	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
5	Total	n/a	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0

	Vehicles	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
		Variance (Preliminary vs Net Benefit Analysis)										
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
6	Total Transportation Cost	n/a	($0.0)	($0.0)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)
7	Total Savings Variance	n/a	($0.0)	($0.0)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)

K. External Directors/Trustee Fees

Savings Rationale:

Prior to the merger, NSTAR and NU each had separate boards of trustees. With the merger of NSTAR and NU, the number of independent trustees could be reduced.

Projected Savings:

In the Net Benefits Study, projected external directors/trustee fee savings totaled $300,000 for 2011, $1,400,000 for 2012 and $1,400,000 for 2013, for total savings of $3.1 million by December 31, 2013.

Integration Activities:

Following the merger closing date, Northeast Utilities combined the NU and NSTAR boards. The new board structure has reduced the number of Trustees and revised the compensation model. This action will result in approximately $1.2 million in annual savings beginning in 2013.

Due to the nature of these savings, there is no impact to the ability of the Operating Companies to perform the work necessary to serve customers on a safe and reliable basis.

Savings Achieved:

Through December 31, 2013, total savings in this functional area total $1.4 million. Annual savings based on integration efforts to date are in the range of $1.2 million.

TABLE K
External Directors Savings
($ in Millions)

Original Net Benefit Analysis

	External Directors / Trustee Fees	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
1	Total Fees	$0.3	$1.4	$1.4	$1.4	$1.5	$1.5	$1.5	$1.5	$1.6	$1.6	$1.6
2	Total	$0.3	$1.4	$1.4	$1.4	$1.5	$1.5	$1.5	$1.5	$1.6	$1.6	$1.6

Preliminary Results

	External Directors / Trustee Fees	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
3	Inflation Rate			1.6%	2.4%	1.9%	1.9%	1.6%	1.5%	1.4%	1.4%	1.4%
4	Total Fees	n/a	$0.2	$1.2	$1.2	$1.2	$1.2	$1.3	$1.3	$1.3	$1.3	$1.3
5	Total	n/a	$0.2	$1.2	$1.2	$1.2	$1.2	$1.3	$1.3	$1.3	$1.3	$1.3

Variance (Preliminary vs Net Benefit Analysis)

	External Directors / Trustee Fees	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
6	Total Fees	n/a	($1.1)	($0.2)	($0.3)	($0.3)	($0.3)	($0.3)	($0.3)	($0.3)	($0.3)	($0.3)
7	Total Savings Variance	n/a	($1.1)	($0.2)	($0.3)	($0.3)	($0.3)	($0.3)	($0.3)	($0.3)	($0.3)	($0.3)

L. Association Dues

Savings Rationale:

In the Net Benefits Study, savings were forecast to result from the elimination of EEI membership dues model and other dues that would be reduced with a consolidated entity. The EEI dues model includes decreased rates after the first 500,000 customers and $500 million in electric revenues, decreasing the cost for the combined new company with greater revenue and a larger customer base as compared with two stand alone companies.

Projected Savings:

In the Net Benefits Study, projected association dues savings totaled $100,000 for 2011, $400,000 for 2012 and $400,000 for 2013, for total savings of $900,000 by December 31, 2013.

Integration Activities:

Following the merger close, Northeast Utilities was able to reduce EEI dues because of the size of the combined company. Also, all professional memberships and corporate sponsorships/association fees were reviewed and duplicates were eliminated. Due to the nature of these savings, there is no impact to the ability of the Operating Companies to perform the work necessary to serve customers on a safe and reliable basis.

Savings Achieved

Through December 31, 2013, total savings in this functional area total $500,000. Annual savings based on integration efforts to date are in the range of $400,000.

TABLE L
Association Dues Savings Summary
($ in Millions)

Original Net Benefit Analysis

	Association Dues	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
1	Association Dues	$0.1	$0.4	$0.4	$0.4	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5
2	Total	$0.1	$0.4	$0.4	$0.4	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5

Preliminary Results

	Association Dues	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
3	Inflation Rate			1.6%	2.4%	1.9%	1.9%	1.6%	1.5%	1.4%	1.4%	1.4%
4	Association Dues	n/a	$0.1	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4
5	Total	n/a	$0.1	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4

Variance (Preliminary vs. Net Benefit Analysis)

	Association Dues	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
6	Association Dues	n/a	($0.4)	($0.0)	($0.0)	($0.0)	($0.0)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)
7	Total Savings Variance	n/a	($0.4)	($0.0)	($0.0)	($0.0)	($0.0)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)

M. Credit Facilities

Savings Rationale:

Prior to the merger, neither NSTAR nor Northeast Utilities fully utilized its respective credit lines. The Net Benefits Study anticipated that the post merger organization would be in a better position to schedule its cash flow needs and, as a result, would be in a position to reduce the level of combined credit lines. Savings were also contemplated through avoided commitment fees on the underlying credit lines.

Projected Savings:

In the Net Benefits Study, there were minimal savings associated with credit facilities forecast through December 31, 2013.

Integration Activities:

Consistent with the Net Benefits Analysis, restructuring of credit facilities produced modest savings by December 31, 2013, which are not separately quantified as yet.

TABLE M
Credit Facilities Savings Summary
($ in Millions)

	Credit Facilities	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
		Original Net Benefit Analysis										
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
1	Credit Facility Fees	$0.0	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
2	Total	$0.0	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1

	Credit Facilities	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
		Preliminary Results										
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
3	Inflation Rate			1.6%	2.4%	1.9%	1.9%	1.6%	1.5%	1.4%	1.4%	1.4%
4	Credit Facility Fees	n/a	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
5	Total	n/a	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0

	Credit Facilities	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
		Variance (Preliminary vs. Net Benefit Analysis)										
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
6	Credit Facility Fees	n/a	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)
7	Total Savings Variance	n/a	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)

N. Materials & Supply Procurement

Savings Rationale:

In the Net Benefits Study, savings were expected from increased standardization, purchasing power, and vendor consolidation.

Projected Savings:

In the Net Benefits Study, projected savings for materials and supply procurement totaled $2.6 million for 2011, $10.6 million for 2012 and $10.9 million for 2013.

Integration Activities:

> **Procurement - Contract Rationalization Savings Initiative:** This saving project started the contract consolidation process by focusing on common vendors of NSTAR and Northeast Utilities within the top 80 percent of spend. Through consolidation of vendors and vendor concessions, savings were identified. Ongoing efforts are continuing to identify savings with the smaller common vendors of Northeast Utilities. The effort has lead to material and supply savings of approximately $1.3 million in 2012 and $3.2 million in 2013.
>
> **Standardization & Consolidation of Materials Initiative:** Northeast Utilities is in the process of reviewing materials function across the enterprise. Currently 12 commodity groups consisting of 314 items have been reviewed. To date, the review has led to 104 items being eliminated leading to lower ongoing material cost.

Due to the nature of these savings, there is no impact to the ability of the Operating Companies to perform the work necessary to serve customers on a safe and reliable basis.

Savings Achieved

Through December 31, 2013, total savings of $4.5 million were achieved. Annual savings based on integration efforts to date are in the range of $3.2 million.

TABLE N
Materials & Supply Savings Summary
($ in Millions)

		Original Net Benefit Analysis										
	Material and Supply Procurement	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
1	Material & Supply Procurement	$2.6	$10.6	$10.9	$11.2	$11.4	$11.6	$11.8	$12.0	$12.1	$12.3	$12.5
2	Capitalization Rate	85.7%	85.7%	85.7%	85.7%	85.7%	85.7%	85.7%	85.7%	85.7%	85.7%	85.7%
3	Total O&M Savings	$0.4	$1.5	$1.6	$1.6	$1.6	$1.7	$1.7	$1.7	$1.7	$1.8	$1.8
4	Total Capitalized Savings	$2.2	$9.1	$9.4	$9.6	$9.8	$10.0	$10.1	$10.3	$10.4	$10.6	$10.7
5	Yearly Depreciation	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%
6	Rate Base Return	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%
7	2011	$2.2	$2.1	$2.1	$2.0	$1.9	$1.8	$1.8	$1.7	$1.6	$1.6	$1.5
8	2012		$9.1	$8.8	$8.4	$8.1	$7.8	$7.5	$7.3	$7.0	$6.7	$6.5
9	2013			$9.4	$9.0	$8.7	$8.4	$8.0	$7.8	$7.5	$7.2	$6.9
10	2014				$9.6	$9.2	$8.9	$8.6	$8.2	$7.9	$7.6	$7.4
11	2015					$9.8	$9.4	$9.1	$8.7	$8.4	$8.1	$7.8
12	2016						$10.0	$9.6	$9.2	$8.9	$8.6	$8.2
13	2017							$10.1	$9.7	$9.4	$9.0	$8.7
14	2018								$10.3	$9.9	$9.5	$9.2
15	2019									$10.4	$10.0	$9.7
16	2020										$10.6	$10.2
17	2021											$10.7
18	Total Rate Base (sum lines 7 thru 17)	$2.2	$11.2	$20.2	$29.0	$37.7	$46.3	$54.7	$62.9	$71.0	$78.9	$86.7
19	Revenue Requirements (line 18 * line 6)	$0.4	$2.0	$3.7	$5.3	$6.8	$8.4	$9.9	$11.4	$12.9	$14.3	$15.7
20	O&M and Capital Return Savings (line 3 + line 19)	$0.8	$3.6	$5.2	$6.9	$8.5	$10.1	$11.6	$13.1	$14.6	$16.1	$17.5

	Material and Supply Procurement	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
		Preliminary Results										
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
21	Inflation Rate			1 6%	2 4%	1 9%	1 9%	1 6%	1 5%	1 4%	1 4%	1 4%
22	Material & Supply Procurement	n/a	$1.3	$3.2	$3.2	$3.3	$3.4	$3.4	$3.5	$3.5	$3.6	$3.6
23	Capitalization Rate	n/a	92.0%	85.7%	85.7%	85.7%	85.7%	85.7%	85.7%	85.7%	85.7%	85.7%
24	Total O&M Savings	n/a	$0.1	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5
25	Total Capitalized Savings	n/a	$1.2	$2.7	$2.8	$2.8	$2.9	$2.9	$3.0	$3.0	$3.1	$3.1
26	Yearly Depreciation	n/a	3.3%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%
27	Rate Base Return	n/a	17.4%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%
28	2011	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
29	2012		$1.2	$1.1	$1.1	$1.1	$1.0	$1.0	$0.9	$0.9	$0.9	$0.8
30	2013			$2.7	$2.6	$2.5	$2.4	$2.3	$2.2	$2.2	$2.1	$2.0
31	2014				$2.8	$2.7	$2.6	$2.5	$2.4	$2.3	$2.2	$2.1
32	2015					$2.8	$2.7	$2.6	$2.5	$2.4	$2.3	$2.3
33	2016						$2.9	$2.8	$2.7	$2.6	$2.5	$2.4
34	2017							$2.9	$2.8	$2.7	$2.6	$2.5
35	2018								$3.0	$2.9	$2.8	$2.7
36	2019									$3.0	$2.9	$2.8
37	2020										$3.1	$2.9
38	2021											$3.1
39	Total Rate Base (sum lines 28 thru 38)	n/a	$1.2	$3.8	$6.5	$9.1	$11.6	$14.1	$16.5	$18.9	$21.3	$23.6
40	Revenue Requirements (line 39 * line 27)	n/a	$0.2	$0.7	$1.2	$1.6	$2.1	$2.6	$3.0	$3.4	$3.9	$4.3
41	O&M and Capital Return Savings (line 24 + line 40)	n/a	$0.3	$1.1	$1.6	$2.1	$2.6	$3.0	$3.5	$3.9	$4.4	$4.8

	Material and Supply Procurement	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
		Variance (Preliminary vs Net Benefit Analysis)										
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
42	Material and Supply Procurement	n/a	($3.2)	($4.1)	($5.2)	($6.4)	($7.5)	($8.6)	($9.6)	($10.7)	($11.7)	($12.7)
43	Total Savings Variance	n/a	($3.2)	($4.1)	($5.2)	($6.4)	($7.5)	($8.6)	($9.6)	($10.7)	($11.7)	($12.7)

O. Inventory

Savings Rationale:

In the Net Benefits Study, Northeast Utilities forecast that a combined entity could realize a one time inventory reduction due to inventory duplication.

Projected Savings:

The Net Benefits Study did not forecast savings associated with this function.

Integration Activities:

The Company is currently conducting a comprehensive review of all warehouses and stocking locations to identify opportunities for efficiencies and cost savings while continuing to meet business needs.

Savings Achieved:

At this time there were no savings associated with this integration initiative.

P. Contract Services

Savings Rationale:

In the Net Benefits Study, the post merger organization was expected to have opportunities to consolidate and reduce contract services activities through economies of scale and elimination of non recurring duplicate services, such as tree trimming and construction and similar items.

Projected Savings:

In the Net Benefits Study, projected savings for contract services totaled $2.7 million for 2011, $11 million for 2012 and $11.4 million for 2013.

Integration Activities:

> **Procurement - Contract Rationalization Savings Initiative:** This saving project started the contract consolidation process by focusing on common vendors of NSTAR and Northeast Utilities within the top 80 percent of spend. Through consolidation of vendors and vendor concessions, savings were identified. Ongoing efforts are continuing to identify savings with the smaller common vendors of Northeast Utilities.

Due to the nature of these savings, there is no impact to the ability of the Operating Companies to perform the work necessary to serve customers on a safe and reliable basis.

Savings Achieved

Through December 31, 2013, integration efforts have produced approximately $9.3 million in savings. Annual savings based on integration efforts to date are in the range of $7.3 million.

TABLE P
Contract Services Savings Summary
($ in Millions)

	Contract Services	Original Net Benefit Analysis										
		2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
1	Contract Services	$2.7	$11.0	$11.4	$11.6	$11.9	$12.1	$12.3	$12.5	$12.6	$12.8	$13.0
2	Capitalization Rate	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%
3	Total O&M Savings	$0.9	$3.9	$4.0	$4.1	$4.2	$4.2	$4.3	$4.4	$4.4	$4.5	$4.5
4	Total Capitalized Savings	$1.8	$7.2	$7.4	$7.6	$7.7	$7.9	$8.0	$8.1	$8.2	$8.3	$8.4
5	Yearly Depreciation	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%
6	Rate Base Return	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%
7	2011	$1.8	$1.7	$1.6	$1.6	$1.5	$1.5	$1.4	$1.4	$1.3	$1.3	$1.2
8	2012		$7.2	$6.9	$6.7	$6.4	$6.2	$5.9	$5.7	$5.5	$5.3	$5.1
9	2013			$7.4	$7.1	$6.9	$6.6	$6.4	$6.1	$5.9	$5.7	$5.5
10	2014				$7.6	$7.3	$7.0	$6.8	$6.5	$6.3	$6.0	$5.8
11	2015					$7.7	$7.4	$7.2	$6.9	$6.6	$6.4	$6.2
12	2016						$7.9	$7.6	$7.3	$7.0	$6.8	$6.5
13	2017							$8.0	$7.7	$7.4	$7.1	$6.9
14	2018								$8.1	$7.8	$7.5	$7.2
15	2019									$8.2	$7.9	$7.6
16	2020										$8.3	$8.0
17	2021											$8.4
18	Total Rate Base (sum lines 7 thru 17)	$1.8	$8.9	$15.9	$22.9	$29.8	$36.5	$43.2	$49.7	$56.1	$62.3	$68.5
19	Revenue Requirements (line 18 * line 6)	$0.3	$1.6	$2.9	$4.2	$5.4	$6.6	$7.8	$9.0	$10.2	$11.3	$12.4
20	O&M and Capital Return Savings (line 3 + line 19)	$1.3	$5.5	$6.9	$8.2	$9.6	$10.9	$12.1	$13.4	$14.6	$15.8	$17.0

		Preliminary Results										
	Contract Services	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
21	Inflation Rate			1 6%	2 4%	1 9%	1 9%	1 6%	1 5%	1 4%	1 4%	1 4%
22	Contract Services	n/a	$2.0	$7.3	$7.5	$7.6	$7.7	$7.9	$8.0	$8.1	$8.2	$8.3
23	Capitalization Rate	n/a	62.7%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%
24	Total O&M Savings	n/a	$0.8	$2.5	$2.6	$2.7	$2.7	$2.8	$2.8	$2.8	$2.9	$2.9
25	Total Capitalized Savings	n/a	$1.3	$4.7	$4.8	$4.9	$5.0	$5.1	$5.2	$5.3	$5.3	$5.4
26	Yearly Depreciation	n/a	3.3%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%
27	Rate Base Return	n/a	17.4%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%
28	2011	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
29	2012		$1.3	$1.2	$1.2	$1.1	$1.1	$1.1	$1.0	$1.0	$0.9	$0.9
30	2013			$4.7	$4.6	$4.4	$4.2	$4.1	$3.9	$3.8	$3.6	$3.5
31	2014				$4.8	$4.7	$4.5	$4.3	$4.2	$4.0	$3.9	$3.7
32	2015					$4.9	$4.8	$4.6	$4.4	$4.2	$4.1	$3.9
33	2016						$5.0	$4.8	$4.7	$4.5	$4.3	$4.2
34	2017							$5.1	$4.9	$4.7	$4.6	$4.4
35	2018								$5.2	$5.0	$4.8	$4.6
36	2019									$5.3	$5.1	$4.9
37	2020										$5.3	$5.1
38	2021											$5.4
39	Total Rate Base (sum lines 28 thru 38)	n/a	$1.3	$6.0	$10.6	$15.1	$19.6	$24.0	$28.3	$32.5	$36.6	$40.7
40	Revenue Requirements (line 39 * line 27)	n/a	$0.2	$1.1	$1.9	$2.7	$3.6	$4.4	$5.1	$5.9	$6.7	$7.4
41	O&M and Capital Return Savings (line 24 + line 40)	n/a	$1.0	$3.6	$4.5	$5.4	$6.3	$7.1	$7.9	$8.7	$9.5	$10.3

		Variance (Preliminary vs Net Benefit Analysis)										
	Contract Services	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
42	Contract Services	n/a	($4.5)	($3.2)	($3.7)	($4.2)	($4.6)	($5.0)	($5.4)	($5.9)	($6.3)	($6.7)
43	Total Savings Variance	n/a	($4.5)	($3.2)	($3.7)	($4.2)	($4.6)	($5.0)	($5.4)	($5.9)	($6.3)	($6.7)

Q. Energy Sourcing

Savings Rationale:

In the Net Benefits Study, Northeast Utilities indicated that, although NSTAR's prior merger enabled the attainment of savings in the energy supply area, the circumstances of the NSTAR/Northeast Utilities merger did not indicate that similar savings would be achievable.

Projected Savings:

In the Net Benefits Study, no cost savings were identified in relation to Energy Sourcing.

Integration Activities:

There has not been any integration activities related to energy sourcing due to the distinct regulatory requirements of the Operating Companies.

Savings Achieved

No savings have been achieved in relation to this functional area.

R. Merger-Related Costs

Estimation of Merger-Related Costs:

The Net Benefits Study recognized that merger related savings cannot be achieved without expenditures that enable the merger and are necessary to achieve reduced costs of service. These costs fall into two inter related categories: transaction costs and integration costs. The Net Benefits Study estimated that merger related transaction and integration costs would total approximately $164 million.

Quantification of Actual Merger-Related Costs:

Table R, below, shows that Northeast Utilities has incurred $113.7 million in merger related cost through December 31, 2013, with additional costs anticipated in 2014 associated with the IT reorganization. Executive retention and separation payments are excluded from this analysis in accordance with the merger related settlements.

The Merger Related Costs shown in Table R are expense items only. Capital investment to implement new information systems or other cost reduction initiatives are not included , but rather are eligible for rate base treatment subject to the Department's standard of review for capital projects.

Computation for Ratemaking Treatment

Under Article II (14) of the AG DOER Settlement Agreement, Northeast Utilities is authorized to make a request, in a future rate proceeding, to recover its transaction and reasonable integration costs through the retention of merger related savings to the extent that the Company is able to demonstrate that merger related savings are demonstrated to equal or exceed those costs. Under Article II (13), the eligible merger related costs shall be amortized, for ratemaking purposes, over a 10 year period following the approval of this Settlement Agreement.

TABLE R
Merger Cost Summary
($ in Millions)

		Preliminary Results													
	Merger Cost	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Total
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. L	Col. M
	Integration Cost														
1	Separation Costs														
2	Separation Program			$20.5	$10.1										$30.6
3	Executive Separation[(a)]														$0.0
4	Separation Assistance			$0.2											$0.2
5	Retention Costs[(a)]														$0.0
6	System Integration Costs				$5.8	$5.6									$11.4
7	Telecommunication Costs														$0.0
8	Internal/External Communications														$0.0
9	Transition Costs	$0.2	$3.5	$3.2	$2.0										$8.9
	Adjustment to tie to Accounting's total														
	Transaction Costs														
10	Transaction Costs														
11	Bankers Fees	$11.8	$12.1	$24.1											$48.0
12	Lawyers Fees	$4.2	$2.1	$5.4											$11.7
13	Registration	$0.0	$2.1												$2.1
14	Consultants	$0.9	$0.5												$1.4
15	D&O Liability Tail Coverage	$0.0	$0.0												$0.0
16	Regulatory Process Costs														
17	Legal Fees	$1.2	$3.2												$4.4
18	Registration S4	$0.3	$0.0												$0.4
19	Consultants	$0.0	$0.2												$0.2
20	Total Costs	$18.7	$23.7	$53.4	$17.9	$5.6	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$119.4

(a) Excludes executive separation and retention payments per the AG/OCC Merger Settlement Agreement

(b) Non deductible costs have not been grossed up for taxes.

Eversource Energy
Exhibit No. ES-103

Merger Integration
2015 Annual Interim Report

September 30, 2015

EVERSOURCE

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OVERVIEW

Methodology

This Merger Integration Report presents enterprise-wide information, by functional area, on the merger-related costs incurred and savings achieved in the period between the closing date of the Northeast Utilities/NSTAR merger,[1] April 10, 2012, and September 30, 2015 and forecasted through the first quarter of 2022.

The Merger Integration Report is organized to provide merger-related savings by functional area consistent with the Net Benefits Analysis filed in Docket Number 12-01-07, *Application for Approval of Holding Company Transaction Involving Northeast Utilities and NSTAR* (the Connecticut merger docket) and Docket Number D.P.U. 10-170, *Request for Approval of Merger between NSTAR and Northeast Utilities* (Massachusetts merger docket). In each functional area, Eversource Energy[2] has identified the principal steps taken to achieve merger-related savings. To quantify merger-related savings, Eversource has identified the savings attributable to merger-related integration activities in each functional area.

Differences from the initial Net Benefits Analysis: In the initial Net Benefits Analysis filed in Docket Number D.P.U. 10-170, the net merger-related savings were forecast by year, for a 10-year period, assuming a merger close in 2011. The Merger Savings Summary Table, below, shows that merger-related transaction costs were incurred starting in 2010. However, no savings were achieved until the starting point of the merger integration, which was the merger closing on April 10, 2012. In addition, this report shows that, although total overall savings are currently projected to exceed the projections encompassed in the Net Benefits Analysis, the specific areas from which savings have been achieved are different than originally forecasted, with some areas yielding greater savings than anticipated and others yielding less. This result is to be expected due to the fact that the savings estimates in the Net Benefit Analysis were derived primarily on the basis of past experience with a prior merger. Under the circumstances of the NSTAR/Northeast Utilities merger, savings are arising in differing degrees in each functional area.

Computational Inputs: The Merger Savings Summary Table presents (page 4): (1) actual merger-related costs for 2010 through September 30, 2015; (2) actual merger-related savings for the nine-month period following the merger close in 2012 through September 30, 2015; and (3) merger-related savings forecast for the fourth quarter of 2015 through the first quarter of 2022, concluding the 10-year

[1] "Northeast Utilities" and "NSTAR" refer to the pre-merger holding companies.
[2] "Eversource" or "Eversource Energy" are used generally to represent the current merged company and all of its operating utility subsidiaries (NSTAR Electric Company ("NSTAR Electric"), The Connecticut Light and Power Company ("CL&P"), Public Service Company of New Hampshire ("PSNH"), Western Massachusetts Electric Company ("WMECO"), Yankee Gas Services Company ("Yankee Gas"), and NSTAR Gas Company ("NSTAR Gas")).

period following the merger close (consistent with the annual savings timeframe projected in the Net Benefit Analysis). The inflation factors used in the original Net Benefits Analysis are incorporated beginning in 2016 and for the remaining years of the 10-year period, capturing the cost increases attributable to inflation that are avoided as a result of the elimination of operating costs. For 2012 through 2015, inflation factors have been updated to reflect current factors.

Interim Results as of December 31, 2015

The Merger Integration Report shows that Eversource is projecting to exceed the merger-savings forecast developed for the Net Benefits Analysis. Specifically, the Net Benefits Analysis estimated net merger-related savings for the ten years following the merger to be approximately $784 million on an enterprise-wide basis. The Merger Savings Summary Table, below, shows that the cumulative net savings projection is currently calculated to be $1,053.8 million on an enterprise-wide basis, over the 10-year period following the merger, 2012 through 2022. The projected savings of $1,053.8 million are net of $125.9 million of merger-related costs calculated in Table R, below.

In both Connecticut and Massachusetts, Eversource entered into merger-related settlement agreements designed to ensure net benefits to customers as a result of the merger. A principal term of the settlement agreements was the immediate credit to customers of a portion of the savings expected to result during the settlement periods. In 2012, Eversource made total up-front payments to retail customers in Connecticut and Massachusetts of $46 million in merger savings, which caused the need to accelerate the achievement of savings as compared to the Net Benefits Analysis that was produced prior to the execution of the settlement agreements. Pursuant to the merger-related settlement agreements, executive retention and separation costs are *excluded* from the merger-related costs in this Annual Interim Report.

The summary results show that Eversource has incurred total merger-related costs of $125.9 million through September 30, 2015 and has achieved merger-related savings of $270.9 million through December 31, 2015, resulting in cumulative net savings of $145.0 million through December 31, 2015.

Savings quantifications through December 31, 2015 are presented herein for each functional area covered in the Net Benefits Analysis, with the original projections from Massachusetts Docket No. D.P.U. 10-170 and Connecticut Docket No. 12-01-07 shown first, followed by a computation of the 2015 Annual Interim savings summary, reflecting preliminary results through September 30, 2015.

Table 1
Merger Savings Summary
($ in Millions)

		Category	2010	2011	2012*	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022**	Total
1	A	Total Labor Savings	n/a	n/a	$ 8.6	$ 32.5	$ 41.6	$ 52.3	$ 57.6	$ 60.7	$ 64.0	$ 67.2	$ 70.5	$ 73.8	$ 18.5	$ 547.4
2	B	Administrative & General Overhead	n/a	n/a	-	0.6	0.8	0.9	0.9	0.9	1.0	1.0	1.0	1.1	0.3	8.4
3	C	Advertising	n/a	n/a	0.6	1.3	1.4	1.4	1.4	1.4	1.4	1.5	1.5	1.5	0.4	13.8
4	D	Benefits	n/a	n/a	-	19.3	21.5	22.2	24.8	27.7	30.6	33.6	36.8	40.0	10.0	266.6
5	E	Insurance	n/a	n/a	1.5	2.2	2.2	2.2	2.3	2.3	2.3	2.4	2.4	2.4	0.6	22.8
6	F	Information Systems	n/a	n/a	0.4	0.4	4.8	16.7	17.8	18.5	19.2	20.0	20.8	21.6	5.4	145.6
7	G	Professional Services	n/a	n/a	0.8	1.3	1.3	1.3	1.3	1.3	1.4	1.4	1.4	1.4	0.4	13.2
8	I	Shareholder Services	n/a	n/a	0.3	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.2	6.7
9	J	Vehicles	n/a	n/a	-	-	-	-	-	-	-	-	-	-	-	-
10	K	Directors Fees	n/a	n/a	0.2	1.1	1.1	1.1	1.2	1.2	1.2	1.2	1.2	1.2	0.3	11.2
11	L	Association Dues	n/a	n/a	0.1	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.1	3.9
12	M	Credit Facilities	n/a	n/a	-	-	-	-	-	-	-	-	-	-	-	-
13	N	Materials & Supply Procurement	n/a	n/a	0.4	1.0	3.3	4.5	7.0	8.4	9.9	11.3	12.7	14.1	3.5	76.1
14	P	Contract Services	n/a	n/a	0.9	3.8	4.4	5.1	5.9	6.7	7.5	8.3	9.1	9.8	2.5	64.0
15	R	Merger Related Cost	(18.7)	(23.6)	(53.4)	(16.6)	(12.6)	(1.0)	-	-	-	-	-	-	-	(125.9)
16		**Total Net Savings**	$(18.7)	$ (23.6)	$ (39.5)	$ 48.0	$ 70.9	$ 107.9	$ 121.1	$ 130.3	$ 139.6	$ 149.0	$ 158.5	$ 168.1	$ 42.0	$ 1,053.8
17		Cumulative Savings	$(18.7)	$ (42.3)	$ (81.8)	$ (33.8)	$ 37.1	$ 145.0	$ 266.2	$ 396.5	$ 536.1	$ 685.1	$ 843.6	$ 1,011.8	$ 1,053.8	

A. Corporate & Administrative Labor

Savings Rationale:

In the Net Benefits Analysis, Eversource forecast that reductions in personnel would result from the elimination of duplicative and overlapping Corporate and Administrative functions performed by the two pre-merger organizations. Forecasted savings did not include the results of potential re-engineering or downsizing opportunities that may be available to each company on a standalone basis.

Projected Savings:

In the Net Benefits Analysis, projected labor savings totaled $800,000 for 2011, $10.4 million for 2012, $24.7 million for 2013, $39.8 million for 2014 and $50.1 million for 2015, for cumulative savings of $125.8 million by December 31, 2015. The cumulative number of staffing reductions through the end of 2015 was forecast at 347.

Integration Activities:

Following the close of the merger, staffing reductions resulted from a reorganization of the Corporate & Administrative function and the elimination of redundant positions. Staffing changes were accelerated from the pace contemplated in the Net Benefits Analysis, due to the payment of an upfront savings credit to customers upon the merger close and the imposition of base-rate freezes. Because the positions eliminated were redundant positions in the new, combined operation, there is no impact to the ability of the Eversource Companies[3] to perform the work necessary to serve customers on a safe and reliable basis.

Savings Achieved:

As of September 30, 2015, merger-related staffing reductions and attrition accounted for the elimination of 383 positions since the merger close. "Merger-related" reductions are reductions arising from Eversource's merger integration efforts, such as the consolidation of Legacy NU's and Legacy NSTAR's[4] duplicate corporate functions or systems. Merger-Related job reductions do not include exits from Eversource for other reasons such as retirements, resignations, terminations for cause, deaths, probationary terminations, an exit from

[3] The "Eversource Companies" refers to CL&P, Yankee Gas, WMECO, NSTAR Electric, NSTAR Gas, PSNH, and WMECO.
[4] "Legacy NU" refers to Northeast Utilities and all of its subsidiaries prior to the merger. "Legacy NSTAR" refers to NSTAR and all of its subsidiaries prior to the merger.

certain competitive businesses or reductions due to normal day-to-day business and resource needs. In addition, labor savings from attrition is calculated as the difference between the number of employee exits and the number of new hires, as experienced in the respective period within the Legacy NU and, for Legacy NSTAR employees, in the functional areas encompassed in the Corporate and Administrative group (because Legacy NSTAR did not have a service company structure prior to the merger).

These staffing changes have produced cumulative savings through December 31, 2015 of approximately $149 million including employee-benefits costs and other indirect expenses associated with labor. These savings could not be achieved without the incurrence of certain costs associated with labor reductions. Costs to achieve these savings are included in the computation of Merger-Related Costs.

Labor savings are quantified by calculating the actual annual salary and benefits for positions that were merger-related reductions and by taking an average salary for positions eliminated through attrition.

Savings associated with staffing reductions to implement the new information technology (“IT”) organizational model are not included in this section as those staffing changes are addressed in the IT section below.

TABLE A
Corp & Admin Labor Savings Summary
($ in Millions)

		Original Net Benefit Analysis										
	Corp & Admin Labor	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Saving	2020 Savings	2021 Savings
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
1	Employee Reductions	25	100	100	100	22	-	-	-	-	-	-
2	Cummulative Employee Reductions	25	125	225	325	347	347	347	347	347	347	347
3	Corp & Admin Total Labor Savings	$0.8	$10.4	$24.7	$39.8	$50.1	$53.2	$54.6	$56.0	$57.5	$58.9	$60.3
4	Capitalization Rate	16.1%	16.1%	16.1%	16.1%	16.1%	16.1%	16.1%	16.1%	16.1%	16.1%	16.1%
5	Total O&M Savings	$0.7	$8.7	$20.7	$33.4	$42.0	$44.6	$45.9	$47.0	$48.2	$49.4	$50.7
6	Total Capitalized Savings	$0.1	$1.7	$4.0	$6.4	$8.0	$8.5	$8 8	$9.0	$9.2	$9.5	$9.7
7	Yearly Depreciation	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%
8	Rate Base Return	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%
9	2011	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
10	2012		$1.7	$1.6	$1.5	$1.5	$1.4	$1.4	$1.3	$1.3	$1.2	$1.2
11	2013			$4.0	$3.8	$3.7	$3.5	$3.41	$3.3	$3.2	$3.0	$2.9
12	2014				$6.4	$6.2	$5.9	$5.7	$5.5	$5.3	$5.1	$4.9
13	2015					$8.0	$7.7	$7.5	$7.2	$6.9	$6.7	$6.4
14	2016						$8.5	$8.2	$7.9	$7.6	$7.3	$7.1
15	2017							$8.8	$8.4	$8.1	$7.8	$7.5
16	2018								$9.0	$8.7	$8.3	$8.0
17	2019									$9.2	$8.9	$8.6
18	2020										$9.5	$9.1
19	2021											$9.7
20	Total Rate Base (sum lines 9 thru 19)	$0.1	$1.8	$5.7	$11.9	$19.5	$27.3	$35.0	$42.7	$50.4	$58.0	$65.5
21	Revenue Requirements (line 20 * line 8)	$0.0	$0.3	$1.0	$2.2	$3.5	$5.0	$6.4	$7.8	$9.1	$10.5	$11.9
22	O&M and Capital Return Savings (line 5 + line 21)	$0.7	$9.0	$21.8	$35.6	$45.6	$49.6	$52.2	$54.8	$57.4	$60.0	$62.5

		Preliminary Results										
	Corp & Admin Labor	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Saving	2020 Savings	2021 Savings
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
23	Inflation Rate		n/a	3.00%	3.00%	3.00%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%
24	Employee Reductions	-	200	57	77	49	-	-	-	-	-	-
25	Cummulative Employee Reductions	0	200	257	334	383	383	383	383	383	383	383
26	Corp & Admin Total Labor Savings	n/a	$9.7	$36 1	$46.0	$57.2	$62.3	$64 1	$65.9	$67.8	$69.8	$71.8
27	Capitalization Rate	n/a	13.40%	12.84%	13.77%	14.32%	16.05%	16.05%	16.05%	16.05%	16.05%	16.05%
28	Total O&M Savings	n/a	$8.4	$31 5	$39.6	$49.0	$52.3	$53.8	$55.4	$56.9	$58.6	$60.3
29	Total Capitalized Savings	n/a	$1 3	$4.6	$6.3	$8.2	$10.0	$10 3	$10.6	$10.9	$11.2	$11.5
30	Yearly Depreciation	n/a	3 26%	3.32%	3.22%	3.30%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%
31	Rate Base Return	n/a	17.38%	17 22%	16.48%	16.66%	18.15%	18.15%	18.15%	18.15%	18 15%	18.15%
32	2011	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
33	2012		$1.3	$1.3	$1.2	$1 2	$1.1	$1.1	$1.0	$1.0	$1.0	$0.9
34	2013			$4.6	$4.5	$4 3	$4.1	$3.99	$3.8	$3.7	$3.6	$3.4
35	2014				$6.3	$6 1	$5.9	$5.7	$5.4	$5 2	$5.0	$4.9
36	2015					$8 2	$7.9	$7.6	$7.3	$7.0	$6.8	$6.5
37	2016						$10.0	$9.6	$9.3	$8 9	$8.6	$8.3
38	2017							$10.3	$9.9	$9 5	$9.2	$8.8
39	2018								$10.6	$10.2	$9.8	$9.5
40	2019									$10.9	$10 5	$10.1
41	2020										$11 2	$10.8
42	2021											$11.5
43	Total Rate Base (sum lines 32 thru 42)	n/a	$1.3	$5.9	$12.0	$19.8	$29.0	$38.2	$47.4	$56.5	$65.7	$74.8
44	Revenue Requirements (line 43 * line 31)	n/a	$0.2	$1.0	$2.0	$3 3	$5.3	$6.9	$8.6	$10.3	$11 9	$13.6
45	O&M and Capital Return Savings (line 28 + line 44)	n/a	$8.6	$32.5	$41.6	$52.3	$57.6	$60.7	$64.0	$67.2	$70 5	$73.8

		Variance (Preliminary Results vs Net Benefit Analysis)										
	Corp & Admin Labor	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Saving	2020 Savings	2021 Savings
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
46	Corp & Admin Labor (line 45 - line 22)	n/a	($0.4)	$10.7	$6.1	$6.8	$8.0	$8 5	$9.2	$9.8	$10.6	$11.3
47	Total Savings Variance	n/a	($0.4)	$10.7	$6.1	$6.8	$8.0	$8 5	$9.2	$9.8	$10.6	$11.3

B. Administrative & General Overhead

Savings Rationale:

Administrative and general overhead costs include office supplies, telephone expenses, employee business expenses and other miscellaneous costs. Administrative and general overhead was anticipated to decrease as corporate personnel are reduced.

Projected Savings:

In the Net Benefits Analysis, projected administrative and general overhead savings totaled $300,000 for 2012, $700,000 for 2013, $1.1 million for 2014 and $1.4 million for 2015, for cumulative savings of approximately $3.5 million by December 31, 2015.

Integration Activities:

Following the close of the merger, staffing reductions resulted from a reorganization of the Corporate & Administrative function and the elimination of redundant positions. Initiatives include consolidated procurement for office supplies and paper across the combined Company resulting in improved pricing and rebates. Additionally, Eversource was able to realize savings on printer and telephone costs. Due to the nature of these savings, there is no impact to the ability of the Eversource Companies to perform the work necessary to serve customers on a safe and reliable basis.

Savings Achieved:

Through December 31, 2015, cumulative savings of approximately $2.5 million have resulted from the creation of purchasing leverage due to the larger Eversource footprint, which allowed for negotiation of new reduced contracts for office supplies, paper supply, printer and telephone support. Annual savings based on integration efforts to date are in the range of $900,000.

TABLE B
Admin & General Savings Summary
($ in Millions)

		Original Net Benefit Analysis										
	Admin & General Overhead	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
1	Total Savings	$0.0	$0.3	$0.7	$1.1	$1.4	$1.5	$1.5	$1.5	$1.6	$1.6	$1.6
2	Capitalization Rate	16.1%	16.1%	16.1%	16.1%	16.1%	16.1%	16.1%	16.1%	16.1%	16.1%	16.1%
3	Total O&M Savings	$0.0	$0.2	$0.6	$1.0	$1.2	$1.3	$1.3	$1.3	$1.3	$1.3	$1.3
4	Total Capitalized Savings	$0.0	$0.0	$0.1	$0.2	$0.2	$0.2	$0.2	$0.2	$0.3	$0.3	$0.3
5	Yearly Depreciation	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%
6	Rate Base Return	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%
7	2011	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
8	2012		$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
9	2013			$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
10	2014				$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.1	$0.1
11	2015					$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2
12	2016						$0.2	$0.2	$0.2	$0.2	$0.2	$0.2
13	2017							$0.2	$0.2	$0.2	$0.2	$0.2
14	2018								$0.2	$0.2	$0.2	$0.2
15	2019									$0.3	$0.2	$0.2
16	2020										$0.3	$0.2
17	2021											$0.3
18	Total Rate Base (sum lines 7 thru 17)	$0.0	$0.1	$0.2	$0.3	$0.6	$0.8	$1.0	$1.2	$1.4	$1.6	$1.8
19	Revenue Requirements (line 18 * line 6)	$0.0	$0.0	$0.0	$0.1	$0.1	$0.1	$0.2	$0.2	$0.3	$0.3	$0.3
20	O&M and Capital Return Savings (line 3 + line 19)	$0.0	$0.3	$0.6	$1.0	$1.3	$1.4	$1.5	$1.5	$1.6	$1.6	$1.7

		Preliminary Results										
	Admin & General Overhead	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
21	Inflation Rate		1 79%	1 56%	1 51%	1 06%	1 85%	1 64%	1 48%	1 43%	1 40%	1 39%
22	Total Savings	n/a	$0.0	$0.7	$0.9	$0.9	$1.0	$1.0	$1.0	$1.0	$1.0	$1.0
23	Capitalization Rate	n/a	13.40%	12.84%	13.77%	14.32%	16.05%	16.05%	16.05%	16.05%	16.05%	16.05%
24	Total O&M Savings	n/a	$0.0	$0.6	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.9
25	Total Capitalized Savings	n/a	$0.0	$0.1	$0.1	$0.1	$0.2	$0.2	$0 2	$0.2	$0.2	$0.2
26	Yearly Depreciation	n/a	3.26%	3 32%	3.22%	3.30%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%
27	Rate Base Return	n/a	17.38%	17.22%	16.48%	16.66%	18.15%	18.15%	18.15%	18.15%	18.15%	18.15%
28												
29	2011	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
30	2012		$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
31	2013			$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
32	2014				$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
33	2015					$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
34	2016						$0.2	$0.1	$0.1	$0.1	$0.1	$0.1
35	2017							$0.2	$0.1	$0.1	$0.1	$0.1
36	2018								$0.2	$0.2	$0.1	$0.1
37	2019									$0.2	$0.2	$0.1
38	2020										$0.2	$0.2
39	2021											$0.2
40	Total Rate Base (sum lines 29 thru 39)	n/a	$0.0	$0.1	$0.2	$0.3	$0.5	$0.6	$0.8	$0.9	$1.0	$1.1
41	Revenue Requirements (line 40 * line 27)	n/a	$0.0	$0.0	$0.0	$0.1	$0.1	$0.1	$0.1	$0.2	$0.2	$0.2
42	O&M and Capital Return Savings (line 24 + line 41)	n/a	$0.0	$0.6	$0.8	$0.9	$0.9	$0.9	$1.0	$1.0	$1.0	$1.1

		Variance (Preliminary vs Net Benefit Analysis)										
	Admin & General Overhead	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
43	Admin & General Overhead	n/a	($0.3)	($0.0)	($0.2)	($0.4)	($0.5)	($0.5)	($0.5)	($0.6)	($0.6)	($0.6)
44	Total Savings Variance	n/a	($0.3)	($0.0)	($0.2)	($0.4)	($0.5)	($0.5)	($0.5)	($0.6)	($0.6)	($0.6)

C. Advertising

Savings Rationale:

In the Net Benefits Analysis, Eversource forecast that the integration of corporate public-relations programs would eliminate the need for duplicative advertising-related design and production, and would reduce advertising fees.

Projected Savings:

In the Net Benefits Analysis, projected advertising savings totaled $200,000 for 2011, $700,000 for 2012, $800,000 for 2013, $800,000 for 2014 and $800,000 for 2015, for cumulative savings of $3.3 million by December 31, 2015.

Integration Activities:

Following the close of the merger, Eversource cancelled the retainer for two advertising consulting agencies, whose services were not necessary under the combined company (savings of $600,000). Eversource also consolidated its media monitoring services and press-release distribution account (savings of $160,000). Eversource reviewed its trade show participation, and as a combined company, was able to reduce the frequency of its participation (savings of $300,000). Savings were also achieved through (1) consolidation of corporate social responsibility reports and the elimination of paper production (savings of $177,000); (2) consolidation of existing Legacy NSTAR and Legacy NU Copyright Clearance Center contracts into one contract (savings of $2,000); (3) consolidation of the Legacy NSTAR and Legacy NU newsletters and collateral development documents from 45 publications to less than 10 (savings of $100,000). Due to the nature of these savings, there is no impact to the ability of the Eversource Companies to perform the work necessary to serve customers on a safe and reliable basis.

Savings Achieved:

Through December 31, 2015, cumulative savings of approximately $4.7 million were achieved through integration and consolidation. Annual savings based on integration efforts to date are in the range of $1.4 million.

TABLE C
Advertising Savings Summary
($ in Millions)

		Original Net Benefit Analysis										
	Advertising	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
1	Advertising	$0.2	$0.7	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.9	$0.9
2	Total Savings	$0.2	$0.7	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.9	$0.9

		Preliminary Results										
	Advertising	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
3	Inflation Rate		1.79%	1.56%	1.51%	1.06%	1.85%	1.64%	1.48%	1.43%	1.40%	1.39%
4	Advertising	n/a	$0.6	$1.3	$1.4	$1.4	$1.4	$1.4	$1.4	$1.5	$1.5	$1.5
5	Total Savings	n/a	$0.6	$1.3	$1.4	$1.4	$1.4	$1.4	$1.4	$1.5	$1.5	$1.5

		Variance (Preliminary vs. Net Benefit Analysis)										
	Advertising	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
6	Advertising	n/a	($0.1)	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6
7	Total Savings Variance	n/a	($0.1)	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6

D. Benefits Administration

Savings Rationale:

In the Net Benefits Analysis, Eversource forecast that cost savings in benefits administration could occur in several areas, primarily through increased purchasing power in negotiating third-party administration fees and integration of benefit plans.

Projected Savings:

In the Net Benefits Analysis, projected benefits-administration savings totaled $1.4 million for 2011, $5.8 million for 2012, $6.1 million for 2013, $6.4 million for 2014 and $6.7 million for 2015, for cumulative savings of approximately $26.4 million by December 31, 2015.

Integration Activities:

Eversource has undertaken several activities to integrate and align the benefit plans for employees. Eversource first performed a comprehensive review of the legacy benefit plans enabling plan consolidation. Eversource also conducted RFPs for active and retiree health and welfare programs. Through this competitive bidding process, significant value was achieved in the following awards:

Provider	Coverage Type
Cigna	Medical and Prescription
Express Scripts	Prescription Drugs
Delta Dental	Dental
VSP	Vision
Minnesota Life	Life Insurance
KGA	Employee Assistance Program

Effective January 1, 2013, new health and welfare benefits were implemented for all non-represented employees. During 2013, as collective bargaining unit contracts expired, new health plans were successfully negotiated with the largest unions. By January 1, 2014, nearly all Eversource employees will have the same standard health plan designs. In addition, effective April 2, 2013, retirement benefits to new Eversource employees took the form of an enhanced defined contribution plan, instead of a defined benefit plan. This will reduce pension liabilities and cost volatility over time.

Due to the nature of these savings, there is no impact to the ability of the Eversource Companies to perform the work necessary to serve customers on a safe and reliable basis.

Savings Achieved:

Through December 31, 2015, cumulative savings estimated at $83.4 million were achieved through integration and consolidation**.** Annual savings based on integration efforts to date are in the range of $28.3 million.

TABLE D
Benefits Administration Savings Summary
($ in Millions)

		Original Net Benefit Analysis										
	Benefits Administration	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
1	Total Benefits Savings	$1.4	$5.8	$6.1	$6.4	$6.7	$7.0	$7.3	$7.7	$8.0	$8.4	$8.8
2	Capitalization Rate	40.6%	40.6%	40.6%	40.6%	40.6%	40.6%	40.6%	40.6%	40.6%	40.6%	40.6%
3	Total O&M Savings	$0.8	$3.4	$3.6	$3.8	$4.0	$4.1	$4.3	$4.6	$4.8	$5.0	$5.2
4	Total Capitalized Savings	$0.6	$2.3	$2.5	$2.6	$2.7	$2.8	$3.0	$3.1	$3.3	$3.4	$3.6
5	Yearly Depreciation	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%
6	Rate Base Return	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%
7	2011	$0.6	$0.5	$0.5	$0.5	$0.5	$0.5	$0.4	$0.4	$0.4	$0.4	$0.4
8	2012		$2.3	$2.3	$2.2	$2.1	$2.0	$1.9	$1.9	$1.8	$1.7	$1.7
9	2013			$2.5	$2.4	$2.3	$2.2	$2.1	$2.1	$2.0	$1.9	$1.8
10	2014				$2.6	$2.5	$2.4	$2.3	$2.2	$2.1	$2.1	$2.0
11	2015					$2.7	$2.6	$2.5	$2.4	$2.3	$2.2	$2.2
12	2016						$2.8	$2.7	$2.6	$2.5	$2.4	$2.3
13	2017							$3.0	$2.9	$2.8	$2.7	$2.6
14	2018								$3.1	$3.0	$2.9	$2.8
15	2019									$3.3	$3.1	$3.0
16	2020										$3.4	$3.3
17	2021											$3.6
18	Total Rate Base (sum lines 8 thru 17)	$0.6	$2.9	$5.3	$7.6	$10.1	$12.5	$15.0	$17.6	$20.2	$22.9	$25.6
19	Revenue Requirements (line 17 * line 7)	$0.1	$0.5	$1.0	$1.4	$1.8	$2.3	$2.7	$3.2	$3.7	$4.2	$4.7
20	O&M and Capital Return Savings (line 3 + line 19)	$0.9	$4.0	$4.6	$5.2	$5.8	$6.4	$7.1	$7.8	$8.4	$9.2	$9.9

	Benefits Administration	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
		Preliminary Results										
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
21	Inflation Rate		n/a	1.90%	2.50%	1.40%	4.77%	4.85%	4.81%	4.80%	4.81%	4.84%
22	Total Benefits Savings	n/a	$0.0	$27.2	$27.9	$28 3	$29.6	$31.1	$32.6	$34.1	$35.8	$37.5
23	Capitalization Rate	n/a	n/a	34.92%	33.78%	38.40%	40.61%	40.61%	40.61%	40.61%	40.61%	40.61%
24	Total O&M Savings	n/a	n/a	$17.7	$18.5	$17.4	$17.6	$18.4	$19.3	$20.3	$21.2	$22.3
25	Total Capitalized Savings	n/a	n/a	$9 5	$9.4	$10 9	$12.0	$12.6	$13.2	$13.9	$14.5	$15.2
26	Yearly Depreciation	n/a	n/a	3.32%	3.22%	3.30%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%
27	Rate Base Return	n/a	n/a	17.22%	16.48%	16.66%	18.15%	18.15%	18.15%	18.15%	18 15%	18 15%
28	2011	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
29	2012		n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
30	2013			$9.5	$9.2	$8.9	$8.5	$8.2	$7.9	$7.6	$7.3	$7.0
31	2014				$9.4	$9.1	$8.7	$8.4	$8.1	$7.8	$7.5	$7.2
32	2015					$10.9	$10.5	$10.1	$9.7	$9.3	$9.0	$8.7
33	2016						$12.0	$11.6	$11.2	$10.7	$10.3	$10.0
34	2017							$12.6	$12.1	$11.7	$11.3	$10.8
35	2018								$13.2	$12.7	$12.3	$11.8
36	2019									$13.9	$13.3	$12.8
37	2020										$14.5	$14.0
38	2021											$15.2
39	Total Rate Base (sum lines 29 thru 38)	n/a	$0.0	$9.5	$18.6	$28.9	$39.7	$50.9	$62.2	$73.7	$85.5	$97.6
40	Revenue Requirements (line 38 * line 28)	n/a	$0.0	$1.6	$3.1	$4.8	$7.2	$9.2	$11.3	$13.4	$15.5	$17.7
41	O&M and Capital Return Savings (line 24 + line 40)	n/a	$0.0	$19.3	$21.5	$22.2	$24.8	$27.7	$30.6	$33.6	$36.8	$40.0

	Benefits Administration	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
		Variance (Preliminary vs Net Benefit Analysis)										
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
42	Benefits Administration	n/a	($4.0)	$14.8	$16.4	$16.4	$18.4	$20.6	$22.9	$25.2	$27.6	$30 1
43	Total Savings Variance	n/a	($4.0)	$14.8	$16.4	$16.4	$18.4	$20.6	$22.9	$25.2	$27.6	$30 1

E. Insurance

Savings Rationale:

In the Net Benefits Analysis, Eversource forecasted the combined company would be able to extend its coverage with its carriers over a larger asset and loss experience base, which would reduce overall cost. Combination of the insurance programs would also provide an opportunity to reassess needed coverage levels and related deductibles based on the loss experience and risk profile of the combined company.

Projected Savings:

In the Net Benefits Analysis, projected insurance savings totaled $500,000 for 2011, $2.2 million for 2012, $2.2 million for 2013, $2.3 for 2014 and $2.3 million for 2015, for cumulative savings of $9.5 million by December 31, 2015.

Integration Activities:

Following the merger close, Eversource reviewed existing insurance policies and coverage and combined the Legacy NU and Legacy NSTAR policies as those policies expired, resulting in better pricing for the combined company than on a stand-alone basis. Due to the nature of these savings, there is no impact to the ability of the Eversource Companies to perform the work necessary to serve customers on a safe and reliable basis.

Savings Achieved:

Through December 31, 2015, cumulative savings of approximately $8.1 million were achieved through integration and consolidation. Annual savings based on integration efforts to date are in the range of $2.2 million.

TABLE E
Insurance Savings Summary
($ in Millions)

	Insurance	Original Net Benefit Analysis										
		2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
1	Insurance	$0.5	$2.2	$2.2	$2.3	$2.3	$2.4	$2.4	$2.4	$2.5	$2.5	$2.5
2	Total Savings	$0.5	$2.2	$2.2	$2.3	$2.3	$2.4	$2.4	$2.4	$2.5	$2.5	$2.5

	Insurance	Preliminary Results										
		2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
3	Inflation Rate		1.79%	1.56%	1.51%	1.06%	1.85%	1.64%	1.48%	1.43%	1.40%	1.39%
4	Insurance	n/a	$1.5	$2.2	$2.2	$2.2	$2.3	$2.3	$2.3	$2.4	$2.4	$2.4
5	Total Savings	n/a	$1.5	$2.2	$2.2	$2.2	$2.3	$2.3	$2.3	$2.4	$2.4	$2.4

	Insurance	Variance (Preliminary vs Net Benefit Analysis)										
		2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
6	Insurance	n/a	($0.7)	($0.0)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)
7	Total Savings Variance	n/a	($0.7)	($0.0)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)

F. Information Systems

Savings Rationale:

In the Net Benefits Analysis, IT-related capital savings were expected to result from the avoidance and elimination of duplicate or unnecessary system development expenditures and the creation of a common IT infrastructure and architecture across the combined company. In addition, the combined entity was expected to avoid system development costs. Also in the Nets Benefit Analysis, IT-related O&M cost savings were expected as a result of the avoidance of leasing desktop computers because of the reduced number of positions requiring workstations. Savings were expected to occur due to the elimination of software and hardware leases, and associated maintenance, resulting from the migration to a common operating platform.

Projected Savings:

In the Net Benefits Analysis, projected IT savings totaled $200,000 for 2011, $2.3 million for 2012, $5.4 million for 2013, $8.7 million for 2014 and $10.9 million for 2015, for cumulative savings of approximately $27.5 million by December 31, 2015.

Integration Activities:

Eversource has consolidated its Corporate Income Tax Return Reporting Systems and Claims Management Systems. Eversource has also upgraded and integrated the existing PowerPlant installations and implemented one budgeting system across the Eversource Companies. In addition, Eversource has consolidated email systems**,** eliminating issues with email compatibility and calendaring and reducing email support cost. Eversource has also addressed an immediate need to share applications among the Eversource Companies by expanding cross-company application sharing environments in Westwood, MA and Windsor, CT. The cost of these initiatives is included as Merger-Related Costs, below.

In October 2013, Eversource announced an initiative involving the reorganization of the IT department. An estimate of the net labor savings occurring thru September 30, 2014 is included in this section. The estimate includes labor savings from the reduction in Eversource staff; estimated contracted savings from elimination of current contractors and the estimated cost of new contractors. The net amount is included in the O&M savings amount. The costs associated with the IT department reorganization are included in the Merger-Related Cost section.

The reorganization of the IT Organization will have no impact on the ability of the Eversource Companies to perform the work necessary to serve customers on a safe and reliable basis under routine conditions and under storm conditions.

Savings Achieved:

As of December 31, 2015, cumulative O&M savings of approximately $22.3 million were achieved through integration and consolidation. Annual savings based on integration efforts to date are in the range of $16.7 million.

TABLE F
IT O&M & Capital Savings Summary
($ in Millions)

		Original Net Benefit Analysis										
	IT Savings	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
1	Total O&M Savings	$0 1	$0 9	$2 3	$3 6	$4 6	$4 9	$5 0	$5 1	$5 2	$5 4	$5 5
2	Total Capitalized Savings	$0 1	$1 3	$3 1	$5 0	$6 3	$6 7	$6 9	$7 1	$7 2	$7 4	$7 6
3	O&M and Capital Return Savings (line 1 + line 2)	$0 2	$2 3	$5 4	$8 7	$10 9	$11 6	$11 9	$12 2	$12 5	$12 8	$13 1

		Preliminary Results										
	IT Savings	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
4	Inflation Rate		1 79%	1 56%	1 51%	1 06%	1 85%	1 64%	1 48%	1 43%	1 40%	1 39%
5	Total O&M Savings	n/a	$0 4	$0 4	$4 8	$16 7	$17 8	$18 5	$19 2	$20 0	$20 8	$21 6
6	Total Capitalized Savings	n/a	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0
7	Yearly Depreciation	n/a	3 26%	3 32%	3 22%	3 30%	3 70%	3 70%	3 70%	3 70%	3 70%	3 70%
8	Rate Base Return	n/a	17 38%	17 22%	16 48%	16 66%	18 15%	18 15%	18 15%	18 15%	18 15%	18 15%
9	2011	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
10	2012		$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0
11	2013			$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0
12	2014				$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0
13	2015					$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0
14	2016						$0 0	$0 0	$0 0	$0 0	$0 0	$0 0
15	2017							$0 0	$0 0	$0 0	$0 0	$0 0
16	2018								$0 0	$0 0	$0 0	$0 0
17	2019									$0 0	$0 0	$0 0
18	2020										$0 0	$0 0
19	2021											$0 0
20	Total Rate Base (sum lines 9 thru 19)	n/a	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0
21	Revenue Requirements (line 20 * line 8)	n/a	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0	$0 0
22	O&M and Capital Return Savings (line 5 + line 21)	n/a	$0 4	$0 4	$4 8	$16 7	$17 8	$18 5	$19 2	$20 0	$20 8	$21 6

		Variance (Preliminary vs Net Benefit Analysis)										
	IT Savings	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
23	IT O&M & Capital	n/a	($1 8)	($4 9)	($3 9)	$5 9	$6 2	$6 6	$7 0	$7 5	$8 0	$8 5
24	Total Savings Variance	n/a	($1 8)	($4 9)	($3 9)	$5 9	$6 2	$6 6	$7 0	$7 5	$8 0	$8 5

G. **Professional Services**

Savings Rationale:

In the Net Benefits Analysis, Eversource projected that it would work to consolidate and reduce professional-services activities through economies of scope and elimination of non-recurring duplicate services and increased utilization of a broader skill base. It was also contemplated that audit and legal services costs could be reduced to eliminate duplication.

Projected Savings:

In the Net Benefits Analysis, projected professional services savings totaled $700,000 for 2011, $3.0 million for 2012, $3.0 million for 2013, $3.1 million for 2014 and $3.2 million for 2015, for cumulative savings of $13.0 million by December 31, 2015.

Integration Activities:

P-Card/T&E Card Consolidation: This savings project consolidated the existing corporate procurement credit cards with a single vendor, resulting in increased volume rebates. The new corporate procurement cards were fully rolled out to Eversource employees in the second half of 2013 (savings of $130,000 annually).

Staff Augmentation Contract Consolidation (Guidant): This savings project is based on consolidating the management of staff augmentation into a single third party vendor to leverage volume and reduce administration/management fees. Eversource is currently tracking ahead of projected savings by moving from Zempleo to Guidant for payroll services (savings of $100,000 annually).

External Auditor Consolidation: Eversource terminated the duplicative relationship with the Legacy NSTAR auditors (PwC) by keeping the existing the auditors (Deloitte) (savings of approximately $700,000 annually).

Eliminate Westlaw Contract: Eversource integrated the Legacy NSTAR Westlaw service into the Legacy NU service at no additional cost (savings of $65,000 annually).

Eliminate Nixon Peabody Lease: Eversource cancelled the lease for office space at Nixon Peabody in Boston, MA, as the space is no longer needed (savings of $60,000 in annually)**.**

Eliminate Towers Watson NSTAR Fair Values Fees: Savings were derived by avoiding the duplicative engagement of Towers Watson to calculate performance share compensation (savings of $15,000 annually).

Financial Reporting Integration: This effort involved insourcing XBRL/Edgarization 10-K filing requirements. Eversource completes this financial reporting process without external providers. The savings are derived from terminating a third party contract which was providing these services for Legacy NSTAR (savings of $120,000 annually).

Due to the nature of these savings, there is no impact to the ability of the Eversource Companies to perform the work necessary to serve customers on a safe and reliable basis.

Savings Achieved:

Through December 31, 2015, cumulative savings of approximately $4.7 million were achieved through integration and consolidation. Annual savings based on integration efforts to date are in the range of $1.3 million.

TABLE G
Professional Services Savings Summary
($ in Millions)

		Original Net Benefit Analysis										
	Professional Services	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
1	Professional Services	$0.7	$3.0	$3.0	$3.1	$3.2	$3.2	$3.3	$3.3	$3.4	$3.4	$3.5
2	Total Savings	$0.7	$3.0	$3.0	$3.1	$3.2	$3.2	$3.3	$3.3	$3.4	$3.4	$3.5

		Preliminary Results										
	Professional Services	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
3	Inflation Rate	n/a	1.79%	1.56%	1.51%	1.06%	1.85%	1.64%	1.48%	1.43%	1.40%	1.39%
4	Professional Services	n/a	$0.8	$1.3	$1.3	$1.3	$1.3	$1.3	$1.4	$1.4	$1.4	$1.4
5	Total Savings	n/a	$0.8	$1.3	$1.3	$1.3	$1.3	$1.3	$1.4	$1.4	$1.4	$1.4

		Variance (Preliminary vs Net Benefit Analysis)										
	Professional Services	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
6	Professional Services	n/a	($2.1)	($1.8)	($1.8)	($1.9)	($1.9)	($1.9)	($2.0)	($2.0)	($2.0)	($2.1)
7	Total Savings Variance	n/a	($2.1)	($1.8)	($1.8)	($1.9)	($1.9)	($1.9)	($2.0)	($2.0)	($2.0)	($2.1)

H. Facilities

Savings Rationale:

In the Net Benefits Analysis, Eversource indicated that, normally, a post-merger entity will consolidate selected facilities, including service centers, garages, data centers, meter shops, warehousing and other corporate facilities. However, due to the geographic disparity of the post-merger Eversource Companies, facilities integration was not included in the original Net Benefit Analysis.

Projected Savings:

The Net Benefits Analysis did not include savings associated with facilities consolidation.

Integration Activities:

Since the merger, Eversource has undertaken a facilities review across its entire service territory to ensure that its current facilities sufficiently meet operational needs. This initiative follows the merger, but is not tied directly to integration activities.

Savings Achieved:
No merger related savings related to the facilities consolidation have been reflected in this Merger Integration Report.

I. Shareholder Services

Rationale for Savings:

Cost savings are expected to result from the elimination of duplicative shareholder related activities, such as conducting the annual shareholder meeting, proxy services and payment of stock exchange fees. The combination will reduce incremental costs per additional shareholder due to economies of scale.

Projected Savings:

In the Net Benefits Analysis, projected shareholder services savings totaled $100,000 for 2011, $500,000 for 2012, $500,000 for 2013, $500,000 for 2014 and $500,000 for 2015, for cumulative savings of approximately $2.1 million by December 31, 2015.

Integration Activities:

Transfer Agent Services: Eversource issued a Request for Proposals (RFP) for the provision of transfer agent services. The transfer agent's responsibilities include maintaining Eversource's shareholder records, distributing quarterly dividend checks and reinvestment plan statements for the registered shareholder base as well as tax information related to dividends and the sale of shares. It also includes annual distribution of proxy materials to registered shareholders in advance of Eversource's annual meeting of shareholders and compliance with escheatment laws. Computershare was chosen to serve as Eversource's transfer agent under a three-year contact. In addition, Eversource amended various provisions of its dividend reinvestment plan (DRP) to mirror the Legacy NSTAR dividend reinvestment plan. As a result of this action, Eversource was able to avoid the cost and inconvenience to participants of re-registering nearly 10,000 Legacy NSTAR registered holders in the Legacy NU DRP. Eversource also lowered reinvestment fees considerably for legacy shareholders of Legacy NU.

Thomson Reuters Investor Relations (IR) Services: Prior to the merger, Legacy NU and Legacy NSTAR had contracts in place for various Investor Relations services, including management of an Investor Relations website at Legacy NSTAR, with Thomson Reuters. Thomson Reuters continues to provide more abbreviated services under a new consolidated three-year contract. A large portion of these costs are covered by a subsidy from the New York Stock Exchange, Inc. (NYSE) that has historically been available to Eversource.

IPREO: Prior to the merger, Legacy NSTAR had retained IPREO, a market surveillance firm, to assist with its ongoing Investor Relations program. IPREO's services continue with Eversource but at a reduced overall cost as its services qualify under the aforementioned subsidy from the NYSE.

Proxy Solicitor: Prior to the merger, Legacy NU and Legacy NSTAR each retained a proxy solicitor to provide services related to each company's annual meeting of shareholders. An RFP was issued and four companies provided bids. After a comprehensive review of the bids, AST Phoenix Advisory Partners was chosen to provide proxy services for the combined company at a cost that is less than the sum of what each company paid for these services in the past.

Annual Meeting, Proxy Mailings, Broadridge: In conjunction with the annual meeting of shareholders, Legacy NU and Legacy NSTAR distributed proxy materials to its shareholders through an independent agent, Broadridge. The fee consists primarily of postage and related costs to distribute proxy materials. The fee is also a function of the number of accounts managed by Broadridge. The number of accounts now managed by Broadridge after the merger's completion is less than the sum of the Legacy NU and Legacy NSTAR accounts prior to the merger.

Annual Report to Shareholders: Prior to the merger, Legacy NU and Legacy NSTAR produced an Annual Report to Shareholders for distribution to their shareholders in advance of their annual meetings. After the merger, the "combined" Eversource produced an annual report at a cost that was significantly less than the sum of what it cost each company to produce its own 2011 annual report. The combined Eversource also utilized a "Notice & Access" approach in the distribution of its 2012 report. This approach offers shareholders the opportunity to view its proxy materials on the Internet instead of receiving a copy in the mail and reduces both printing and mailing costs.

Rating Agencies: Eversource negotiated lower rating agency fees due to the larger size of the merged company.

Due to the nature of these savings, there is no impact to the ability of the Eversource Companies to perform the work necessary to serve customers on a safe and reliable basis.

Savings Achieved:
Through December 31, 2015, cumulative savings of approximately $2.3 million were achieved through integration and consolidation. Annual savings based on integration efforts to date are in the range of $700,000.

TABLE I
Shareholder Services Savings Summary
($ in Millions)

		Original Net Benefit Analysis										
	Shareholder Services	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
1	Shareholder Services	$0.1	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5
2	Total Savings	$0.1	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5

		Preliminary Results										
	Shareholder Services	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
3	Inflation Rate	n/a	1.79%	1.56%	1.51%	1.06%	1.85%	1.64%	1.48%	1.43%	1.40%	1.39%
4	Shareholder Services	n/a	$0.3	$0.6	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7
5	Total	n/a	$0.3	$0.6	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7

		Variance (Preliminary vs Net Benefit Analysis)										
	Shareholder Services	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
6	Shareholder Services	n/a	($0.2)	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2
7	Total Savings Variance	n/a	($0.2)	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2

J. Vehicles

Savings Rationale:
Prior to the merger, Eversource contemplated that the combined company will reduce the total number of corporate A&G employees. As a result of the reduction in the number of employees, the new company will use fewer passenger cars. Savings will be realized through reduced total operating costs for passenger cars. Reduced reimbursable mileage is reflected in Section D: Administrative and General Overhead.

Projected Savings:

In the Net Benefits Analysis, there were modest amounts of projected vehicle cost savings for 2011, 2012, 2013 and 2014.

Integration Activities:

Vehicle savings achieved through December 31, 2014 were modest as anticipated and are not individually quantified.

TABLE J
Vehicles Savings Summary
($ in Millions)

		Original Net Benefit Analysis										
	Vehicles	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
1	Total Transportation Cost	$0.0	$0.0	$0.0	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
2	Total	$0.0	$0.0	$0.0	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1

		Preliminary Results										
	Vehicles	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
3	Inflation Rate		1.79%	1.56%	1.51%	1.06%	1.85%	1.64%	1.48%	1.43%	1.40%	1.39%
4	Total Transportation Cost	n/a	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
5	Total	n/a	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0

		Variance (Preliminary vs Net Benefit Analysis)										
	Vehicles	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
6	Total Transportation Cost	n/a	($0.0)	($0.0)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)
7	Total Savings Variance	n/a	($0.0)	($0.0)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)

K. External Directors/Trustee Fees

Savings Rationale:

Prior to the merger, Legacy NSTAR and Legacy NU each had separate boards of trustees. With the merger of NSTAR and Northeast Utilities, the number of independent trustees could be reduced.

Projected Savings:

In the Net Benefits Analysis, projected external directors/trustee fee savings totaled $300,000 for 2011, $1.4 million for 2012, $1.4 million for 2013, $1.4 for 2014 and $1.5 million for 2015, for cumulative savings of $6.0 million by December 31, 2015.

Integration Activities:

Following the merger closing date, Eversource combined the former Northeast Utilities and NSTAR boards. The new board structure has reduced the number of Trustees and revised the compensation model. This action resulted in approximately $1.1 million in annual savings beginning in 2013.

Due to the nature of these savings, there is no impact to the ability of the Eversource Companies to perform the work necessary to serve customers on a safe and reliable basis.

Savings Achieved:

Through December 31, 2015, cumulative savings in this functional area total approximately $3.5 million. Annual savings based on integration efforts to date are in the range of $1.1 million.

TABLE K
External Directors Savings
($ in Millions)

	External Directors / Trustee Fees	Original Net Benefit Analysis										
		2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
1	Total Fees	$0.3	$1.4	$1.4	$1.4	$1.5	$1.5	$1.5	$1.5	$1.6	$1.6	$1.6
2	Total	$0.3	$1.4	$1.4	$1.4	$1.5	$1.5	$1.5	$1.5	$1.6	$1.6	$1.6

	External Directors / Trustee Fees	Preliminary Results										
		2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
3	Inflation Rate		1.79%	1.56%	1.51%	1.06%	1.85%	1.64%	1.48%	1.43%	1.40%	1.39%
4	Total Fees	n/a	$0.2	$1.1	$1.1	$1.1	$1.2	$1.2	$1.2	$1.2	$1.2	$1.2
5	Total	n/a	$0.2	$1.1	$1.1	$1.1	$1.2	$1.2	$1.2	$1.2	$1.2	$1.2

	External Directors / Trustee Fees	Variance (Preliminary vs Net Benefit Analysis)										
		2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
6	Total Fees	n/a	($1.1)	($0.3)	($0.3)	($0.3)	($0.3)	($0.3)	($0.3)	($0.4)	($0.4)	($0.4)
7	Total Savings Variance	n/a	($1.1)	($0.3)	($0.3)	($0.3)	($0.3)	($0.3)	($0.3)	($0.4)	($0.4)	($0.4)

L. Association Dues

Savings Rationale:

In the Net Benefits Analysis, savings were forecast to result from the elimination of EEI membership dues model and other dues that would be reduced with a consolidated entity. The EEI dues model includes decreased rates after the first 500,000 customers and $500 million in electric revenues, decreasing the cost for the combined new company with greater revenue and a larger customer base as compared with two stand-alone companies.

Projected Savings:

In the Net Benefits Analysis, projected association dues savings totaled $100,000 for 2011, $400,000 for 2012, $400,000 for 2013, $400,000 for 2014 and $500,000 for 2015 for cumulative savings of approximately $1.8 million by December 31, 2015.

Integration Activities:

Following the merger close, Eversource was able to reduce EEI dues because of the size of the combined company. Also, all professional memberships and corporate sponsorships/association fees were reviewed and duplicates were eliminated. Due to the nature of these savings, there is no impact to the ability of the Eversource Companies to perform the work necessary to serve customers on a safe and reliable basis.

Savings Achieved

Through December 31, 2015, cumulative savings in this functional area total approximately $1.3 million. Annual savings based on integration efforts to date are in the range of $400,000.

TABLE L
Association Dues Savings Summary
($ in Millions)

Original Net Benefit Analysis

	Association Dues	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
1	Association Dues	$0.1	$0.4	$0.4	$0.4	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5
2	Total	$0.1	$0.4	$0.4	$0.4	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5

Preliminary Results

	Association Dues	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
3	Inflation Rate		1.79%	1.56%	1.51%	1.06%	1.85%	1.64%	1.48%	1.43%	1.40%	1.39%
4	Association Dues	n/a	$0.1	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4
5	Total	n/a	$0.1	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4

Variance (Preliminary vs. Net Benefit Analysis)

	Association Dues	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
6	Association Dues	n/a	($0.4)	($0.0)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)
7	Total Savings Variance	n/a	($0.4)	($0.0)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)

M. Credit Facilities

Savings Rationale:

Prior to the merger, neither Legacy NSTAR nor Legacy NU fully utilized its respective credit lines. The Net Benefits Analysis anticipated that the post-merger organization would be in a better position to schedule its cash flow needs and, as a result, would be in a position to reduce the level of combined credit lines. Savings were also contemplated through avoided commitment fees on the underlying credit lines.

Projected Savings:

In the Net Benefits Analysis, there were minimal savings associated with credit facilities forecast through December 31, 2014.

Integration Activities:

Consistent with the Net Benefits Analysis, restructuring of credit facilities produced modest savings and are not individually quantified.

TABLE M
Credit Facilities Savings Summary
($ in Millions)

	Credit Facilities	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
		Original Net Benefit Analysis										
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
1	Credit Facility Fees	$0.0	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
2	Total	$0.0	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1

	Credit Facilities	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
		Preliminary Results										
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
3	Inflation Rate		1.79%	1.56%	1.51%	1.06%	1.85%	1.64%	1.48%	1.43%	1.40%	1.39%
4	Credit Facility Fees	n/a	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
5	Total	n/a	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0

	Credit Facilities	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
		Variance (Preliminary vs. Net Benefit Analysis)										
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
6	Credit Facility Fees	n/a	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)
7	Total Savings Variance	n/a	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)

N. Materials & Supply Procurement

Savings Rationale:

In the Net Benefits Analysis, savings were expected from increased standardization, purchasing power, and vendor consolidation.

Projected Savings:

In the Net Benefits Analysis, projected savings for materials and supply procurement totaled $2.6 million for 2011, $10.6 million for 2012, $10.9 million for 2013, $11.2 million for 2014 and $11.4 million for 2015, for cumulative savings of $46.7 million by December 31, 2015.

Integration Activities:

Procurement - Contract Rationalization Savings Initiative: This saving project started the contract consolidation process by focusing on common vendors of Legacy NSTAR and Legacy NU within the top 80 percent of spend. Through consolidation of vendors and vendor concessions, savings were identified. Ongoing efforts are continuing to identify savings with the smaller common vendors of Eversource.

Standardization & Consolidation of Materials Initiative: Eversource has reviewed the materials function across the enterprise. The review has led to over 100 items being eliminated, leading to lower ongoing material cost.

Due to the nature of these savings, there is no impact to the ability of the Eversource Companies to perform the work necessary to serve customers on a safe and reliable basis.

Savings Achieved

Through December 31, 2015, cumulative savings of approximately $25.2 million were achieved. Annual savings based on integration efforts to date are in the range of $10.3 million.

TABLE N
Materials & Supply Savings Summary
($ in Millions)

		Original Net Benefit Analysis										
	Material and Supply Procurement	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
1	Material & Supply Procurement	$2.6	$10.6	$10.9	$11.2	$11.4	$11.6	$11.8	$12.0	$12.1	$12.3	$12.5
2	Capitalization Rate	85.7%	85.7%	85.7%	85.7%	85.7%	85.7%	85.7%	85.7%	85.7%	85.7%	85.7%
3	Total O&M Savings	$0.4	$1.5	$1.6	$1.6	$1.6	$1.7	$1.7	$1.7	$1.7	$1.8	$1.8
4	Total Capitalized Savings	$2.2	$9.1	$9.4	$9.6	$9.8	$10.0	$10.1	$10.3	$10.4	$10.6	$10.7
5	Yearly Depreciation	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%
6	Rate Base Return	18.2%	18 2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%	18.2%
7	2011	$2.2	$2.1	$2.1	$2.0	$1.9	$1.8	$1.8	$1.7	$1.6	$1.6	$1.5
8	2012		$9.1	$8.8	$8.4	$8.1	$7.8	$7.5	$7.3	$7.0	$6.7	$6.5
9	2013			$9.4	$9.0	$8.7	$8.4	$8.0	$7.8	$7.5	$7.2	$6.9
10	2014				$9.6	$9.2	$8.9	$8.6	$8.2	$7.9	$7.6	$7.4
11	2015					$9.8	$9.4	$9.1	$8.7	$8.4	$8.1	$7.8
12	2016						$10.0	$9.6	$9.2	$8.9	$8.6	$8.2
13	2017							$10.1	$9.7	$9.4	$9.0	$8.7
14	2018								$10.3	$9.9	$9.5	$9.2
15	2019									$10.4	$10.0	$9.7
16	2020										$10.6	$10.2
17	2021											$10.7
18	Total Rate Base (sum lines 7 thru 17)	$2.2	$11.2	$20.2	$29.0	$37.7	$46.3	$54.7	$62.9	$71.0	$78.9	$86.7
19	Revenue Requirements (line 18 * line 6)	$0.4	$2.0	$3.7	$5.3	$6.8	$8.4	$9.9	$11.4	$12.9	$14.3	$15.7
20	O&M and Capital Return Savings (line 3 + line 19)	$0.8	$3.6	$5.2	$6.9	$8.5	$10.1	$11.6	$13.1	$14.6	$16.1	$17.5

		Preliminary Results										
	Material and Supply Procurement	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
21	Inflation Rate		1.79%	1.56%	1.51%	1.06%	1.85%	1.64%	1.48%	1.43%	1.40%	1.39%
22	Material & Supply Procurement	n/a	$1.5	$3 2	$10.2	$10.3	$10 5	$10.6	$10.8	$11.0	$11.1	$11.3
23	Capitalization Rate	n/a	92.02%	89.61%	89 15%	91.88%	85.74%	85.74%	85.74%	85.74%	85.74%	85.74%
24	Total O&M Savings	n/a	$0.1	$0 3	$1.1	$0.8	$1.5	$1.5	$1.5	$1.6	$1.6	$1.6
25	Total Capitalized Savings	n/a	$1.4	$2.8	$9.1	$9.4	$9.0	$9.1	$9.3	$9.4	$9.5	$9.7
26	Yearly Depreciation	n/a	3.26%	3.32%	3.22%	3.30%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%
27	Rate Base Return	n/a	17.38%	17.22%	16.48%	16.66%	18.15%	18 15%	18.15%	18.15%	18.15%	18.15%
28	2011	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
29	2012		$1.4	$1.3	$1.3	$1 2	$1.2	$1.1	$1.1	$1.1	$1.0	$1.0
30	2013			$2.8	$2.7	$2.6	$2.5	$2.4	$2.3	$2.3	$2.2	$2.1
31	2014				$9.1	$8.8	$8.4	$8.1	$7.8	$7.5	$7.2	$7.0
32	2015					$9.4	$9.1	$8.8	$8.4	$8.1	$7.8	$7.5
33	2016						$9.0	$8.6	$8.3	$8.0	$7.7	$7.4
34	2017							$9.1	$8.8	$8.5	$8.1	$7.8
35	2018								$9.3	$8.9	$8.6	$8.3
36	2019									$9.4	$9.0	$8.7
37	2020										$9.5	$9.2
38	2021											$9.7
39	Total Rate Base (sum lines 28 thru 38)	n/a	$1.4	$4.2	$13.1	$22.1	$30.2	$38.2	$46.0	$53.7	$61.3	$68.6
40	Revenue Requirements (line 39 * line 27)	n/a	$0.2	$0.7	$2.2	$3.7	$5.5	$6.9	$8.4	$9.8	$11.1	$12 5
41	O&M and Capital Return Savings (line 24 + line 40)	n/a	$0.4	$1.0	$3.3	$4 5	$7.0	$8.4	$9.9	$11.3	$12.7	$14 1

		Variance (Preliminary vs Net Benefit Analysis)										
	Material and Supply Procurement	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
42	Material and Supply Procurement	n/a	($3.2)	($4.2)	($3.6)	($4.0)	($3.1)	($3.2)	($3.2)	($3.3)	($3.4)	($3.5)
43	Total Savings Variance	n/a	($3.2)	($4.2)	($3.6)	($4.0)	($3.1)	($3.2)	($3.2)	($3.3)	($3.4)	($3.5)

O. Inventory

Savings Rationale:

In the Net Benefits Analysis, Eversource forecast that a combined entity could realize a one-time inventory reduction due to inventory duplication.

Projected Savings:

The Net Benefits Analysis did not forecast savings associated with this function.

Integration Activities:

Eversource reviewed its warehouses and stocking locations and did not identify any merger related cost savings.

Savings Achieved:

At this time there are no merger related savings associated with this integration initiative.

P. Contract Services

Savings Rationale:

In the Net Benefits Analysis, the post-merger organization was expected to have opportunities to consolidate and reduce contract services activities through economies of scale and elimination of non-recurring duplicate services, such as tree trimming and construction and similar items.

Projected Savings:

In the Net Benefits Analysis, projected savings for contract services totaled $2.7 million for 2011, $11.0 million for 2012, $11.4 million for 2013, $11.6 million for 2014 and $11.9 million for 2015, for cumulative savings of $48.6 million by December 31, 2015.

Integration Activities:

> **Procurement - Contract Rationalization Savings Initiative:** This saving project started the contract consolidation process by focusing on common vendors of Legacy NSTAR and Legacy NU within the top 80 percent of spend. Through consolidation of vendors and vendor concessions, savings were identified. Ongoing efforts are continuing to identify savings with the smaller common vendors of Eversource.

Due to the nature of these savings, there is no impact to the ability of the Eversource Companies to perform the work necessary to serve customers on a safe and reliable basis.

Savings Achieved

Through December 31, 2015, cumulative savings in this functional area total approximately $23.6 million in savings. Annual savings based on integration efforts to date are in the range of $7.3 million.

TABLE P
Contract Services Savings Summary
($ in Millions)

		Original Net Benefit Analysis										
	Contract Services	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
1	Contract Services	$2.7	$11.0	$11.4	$11.6	$11.9	$12.1	$12.3	$12.5	$12.6	$12.8	$13.0
2	Capitalization Rate	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%
3	Total O&M Savings	$0.9	$3.9	$4.0	$4.1	$4.2	$4.2	$4.3	$4.4	$4.4	$4.5	$4.5
4	Total Capitalized Savings	$1.8	$7.2	$7.4	$7.6	$7.7	$7.9	$8.0	$8.1	$8.2	$8.3	$8.4
5	Yearly Depreciation	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%
6	Rate Base Return	18.2%	18.2%	18 2%	18.2%	18.2%	18.2%	18.2%	18 2%	18.2%	18.2%	18.2%
7	2011	$1.8	$1.7	$1.6	$1.6	$1.5	$1.5	$1.4	$1.4	$1.3	$1.3	$1.2
8	2012		$7.2	$6.9	$6.7	$6.4	$6.2	$5.9	$5.7	$5.5	$5.3	$5.1
9	2013			$7.4	$7.1	$6.9	$6.6	$6.4	$6.1	$5.9	$5.7	$5.5
10	2014				$7.6	$7.3	$7.0	$6.8	$6.5	$6.3	$6.0	$5.8
11	2015					$7.7	$7.4	$7 2	$6.9	$6.6	$6.4	$6.2
12	2016						$7.9	$7.6	$7.3	$7.0	$6.8	$6.5
13	2017							$8.0	$7.7	$7.4	$7.1	$6.9
14	2018								$8.1	$7.8	$7.5	$7.2
15	2019									$8.2	$7.9	$7.6
16	2020										$8.3	$8.0
17	2021											$8.4
18	Total Rate Base (sum lines 7 thru 17)	$1.8	$8.9	$15.9	$22.9	$29.8	$36.5	$43.2	$49.7	$56.1	$62.3	$68.5
19	Revenue Requirements (line 18 * line 6)	$0.3	$1.6	$2.9	$4.2	$5.4	$6.6	$7.8	$9.0	$10.2	$11.3	$12.4
20	O&M and Capital Return Savings (line 3 + line 19)	$1.3	$5.5	$6.9	$8.2	$9.6	$10.9	$12.1	$13.4	$14.6	$15.8	$17.0

			Preliminary Results									
	Contract Services	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
21	Inflation Rate		1.79%	1.56%	1 51%	1.06%	1.85%	1.64%	1.48%	1.43%	1.40%	1.39%
22	Contract Services	n/a	$1.8	$7.3	$7 2	$7.3	$7.4	$7.6	$7.7	$7.8	$7.9	$8.0
23	Capitalization Rate	n/a	62.77%	60.96%	61.05%	61.46%	65.00%	65.00%	65.00%	65.00%	65.00%	65.00%
24	Total O&M Savings	n/a	$0.7	$2.8	$2.8	$2.8	$2.6	$2.6	$2.7	$2.7	$2.8	$2.8
25	Total Capitalized Savings	n/a	$1.2	$4.4	$4.4	$4.5	$4.8	$4.9	$5.0	$5 1	$5.1	$5.2
26	Yearly Depreciation	n/a	3.26%	3.32%	3 22%	3.30%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%
27	Rate Base Return	n/a	17 38%	17.22%	16.48%	16.66%	18 15%	18.15%	18.15%	18.15%	18.15%	18 15%
28	2011	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
29	2012		$1.2	$1 1	$1.1	$1.0	$1.0	$1.0	$0.9	$0.9	$0.9	$0.8
30	2013			$4.4	$4.3	$4.1	$4.0	$3.8	$3.7	$3.5	$3.4	$3.3
31	2014				$4.4	$4.3	$4.1	$3 9	$3.8	$3.7	$3.5	$3.4
32	2015					$4.5	$4.3	$4 2	$4.0	$3.9	$3.7	$3.6
33	2016						$4.8	$4.7	$4.5	$4.3	$4.2	$4.0
34	2017							$4 9	$4.7	$4.6	$4.4	$4.2
35	2018								$5.0	$4.8	$4.6	$4.5
36	2019									$5.1	$4.9	$4.7
37	2020										$5.1	$4.9
38	2021											$5.2
39	Total Rate Base (sum lines 28 thru 38)	n/a	$1.2	$5 5	$9.8	$14.0	$18.2	$22.5	$26.6	$30.7	$34.7	$38.6
40	Revenue Requirements (line 39 * line 27)	n/a	$0.2	$1.0	$1.6	$2.3	$3.3	$4 1	$4.8	$5.6	$6.3	$7.0
41	O&M and Capital Return Savings (line 24 + line 40)	n/a	$0.9	$3.8	$4.4	$5.1	$5.9	$6.7	$7.5	$8.3	$9.1	$9.8

			Variance (Preliminary vs Net Benefit Analysis)									
	Contract Services	2011 Savings	2012 Savings	2013 Savings	2014 Savings	2015 Savings	2016 Savings	2017 Savings	2018 Savings	2019 Savings	2020 Savings	2021 Savings
	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L
42	Contract Services	n/a	($4.6)	($3 1)	($3.8)	($4.4)	($4.9)	($5.4)	($5 9)	($6.3)	($6.7)	($7.2)
43	Total Savings Variance	n/a	($4.6)	($3 1)	($3.8)	($4.4)	($4.9)	($5.4)	($5 9)	($6.3)	($6.7)	($7.2)

Q. Energy Sourcing

Savings Rationale:

In the Net Benefits Analysis, Eversource indicated that, although NSTAR's prior merger enabled the attainment of savings in the energy supply area, the circumstances of the NSTAR/Northeast Utilities merger did not indicate that similar savings would be achievable.

Projected Savings:

In the Net Benefits Analysis, no cost savings were identified in relation to energy sourcing.

Integration Activities:

There has not been any integration activities related to energy sourcing due to the distinct regulatory requirements of the Eversource Companies.

Savings Achieved

No savings have been achieved in relation to this functional area.

R. Merger-Related Costs

Estimation of Merger-Related Costs:

The Net Benefits Analysis recognized that merger-related savings cannot be achieved without expenditures that enable the merger and are necessary to achieve reduced costs of service. These costs fall into two inter-related categories: transaction costs and integration costs. The Net Benefits Analysis estimated that merger-related transaction and integration costs would total approximately $164 million.

Quantification of Actual Merger-Related Costs:

Table R, below, shows that Eversource has incurred $125.9 million in merger-related costs through September 30, 2015 on an enterprise-wide basis. The 2015 costs represent actual merger costs through September 2015. Executive retention and separation payments are excluded from this analysis in accordance with the merger-related settlements.

The Merger-Related Costs shown in Table R are expense items only. Capital investment to implement new information systems or other cost-reduction initiatives is not included, but would be recoverable as a rate-base addition subject to the standard of review for capital projects.

TABLE R
Merger Cost Summary
($ in Millions)

		Preliminary Results													
	Merger Cost	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Total
	Col A	Col B	Col C	Col D	Col E	Col F	Col F	Col G	Col H	Col I	Col J	Col K	Col L	Col L	Col M
	Integration Cost														
1	Separation Costs														
2	Separation Program			$20.5	$9.3	$2.6									$32.4
3	Executive Separation[a]														$0.0
4	Separation Assistance			$0.2											$0.2
5	Retention Costs[a]														$0.0
6	System Integration Costs				$5.8	$7.4	$0.1								$13.3
7	Telecommunication Costs														$0.0
8	Internal/External Communications														$0.0
9	Transition Costs	$0.2	$3.4	$3.2	$1.5	$2.6	$0.9								$11.7
	Transaction Costs														
10	Transaction Costs														
11	Bankers Fees	$11.8	$12.1	$24.1											$48.0
12	Lawyers Fees	$4.2	$2.1	$5.4											$11.7
13	Registration	$0.0	$2.1												$2.1
14	Consultants	$0.9	$0.5												$1.4
15	D&O Liability Tail Coverage	$0.0	$0.0												$0.0
16	Regulatory Process Costs														
17	Legal Fees	$1.2	$3.2												$4.4
18	Registration S4	$0.3	$0.0												$0.4
19	Consultants	$0.0	$0.2												$0.2
20	Total Costs	$18.7	$23.6	53.4	$16.6	$12.6	$1.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$125.9

Exhibit No. ES-104

Total Merger Savings Summary Exhibit

Eversource Energy Service Company

Eversource Energy Service Company
Total Merger Savings Summary Exhibit

Ln.	Merger Cost Category	Total Savings By Enterprise 2012	2013	2014	2015	Total	Reference
1	Corporate & Administrative Labor	$ 8,639,167	$ 32,505,591	$ 41,632,034	$ 39,262,021	$ 122,038,813	Exhibit No. ES-105, Page 1, Line 15
2	Information Systems	$ 409,393	$ 436,499	$ 4,777,119	$ 12,555,218	$ 18,178,228	Exhibit No. ES-106, Page 1, Line 2
3	Insurance	$ 1,494,184	$ 2,164,088	$ 2,196,766	$ 1,665,039	$ 7,520,076	Exhibit No. ES-107, Page 1, Line 3
4	Professional Services	$ 819,087	$ 1,263,774	$ 1,282,857	$ 972,341	$ 4,338,059	Exhibit No. ES-108, Page 1, Line 3
5	Contract Services	$ 883,059	$ 3,796,817	$ 4,431,601	$ 3,857,386	$ 12,968,862	Exhibit No. ES-109, Page 1, Line 15
6	External Directors/Trustee Fees	$ 248,776	$ 1,111,849	$ 1,128,638	$ 855,451	$ 3,344,714	Exhibit No. ES-110, Page 1, Line 3
7	Materials & Supply Procurement	$ 359,058	$ 1,044,542	$ 3,261,470	$ 3,387,474	$ 8,052,544	Exhibit No. ES-111, Page 1, Line 15
8	Administrative & General Overhead	$ -	$ 608,966	$ 833,843	$ 644,026	$ 2,086,835	Exhibit No. ES-112, Page 1, Line 15
9	Association Dues	$ 68,824	$ 387,068	$ 392,913	$ 297,808	$ 1,146,613	Exhibit No. ES-113, Page 1, Line 3
10	Shareholder Services	$ 301,800	$ 648,800	$ 658,597	$ 499,184	$ 2,108,380	Exhibit No. ES-114, Page 1, Line 3
11	Benefits Administration	$ -	$ 19,341,541	$ 21,534,190	$ 16,668,952	$ 57,544,684	Exhibit No. ES-301, Page 1, Line 15
12	Total (Sum Ln 1 - Ln 11)	$ 13,223,348	$ 63,309,535	$ 82,130,025	$ 80,664,899	$ 239,327,808	

Ln.	Merger Cost Category	Total Savings Allocated to Transmission CL&P	NSTAR	PSNH	WMECO	Total	Reference
13	Corporate & Administrative Labor	$ 15,938,269	$ 8,103,377	$ 3,441,495	$ 3,050,970	$ 30,534,111	Exhibit No. ES-105, Page 1, (M)
14	Information Systems	$ 2,374,077	$ 1,207,034	$ 512,626	$ 454,456	$ 4,548,193	Exhibit No. ES-106, Page 1, (M)
15	Insurance	$ 1,197,948	$ 831,720	$ 269,971	$ 341,411	$ 2,641,051	Exhibit No. ES-107, Page 1, (M)
16	Professional Services	$ 691,053	$ 479,789	$ 155,736	$ 196,948	$ 1,523,526	Exhibit No. ES-108, Page 1, (M)
17	Contract Services	$ 402,035	$ 1,050,478	$ 129,689	$ 38,907	$ 1,621,108	Exhibit No. ES-109, Page 1, (M)
18	External Directors/Trustee Fees	$ 532,813	$ 369,925	$ 120,075	$ 151,850	$ 1,174,664	Exhibit No. ES-110, Page 1, (M)
19	Materials & Supply Procurement	$ 249,629	$ 652,256	$ 80,525	$ 24,158	$ 1,006,568	Exhibit No. ES-111, Page 1, (M)
20	Administrative & General Overhead	$ 272,541	$ 138,566	$ 58,849	$ 52,171	$ 522,126	Exhibit No. ES-112, Page 1, (M)
21	Association Dues	$ 182,655	$ 126,815	$ 41,163	$ 52,056	$ 402,690	Exhibit No. ES-113, Page 1, (M)
22	Shareholder Services	$ 146,743	$ 156,864	$ 31,626	$ 33,734	$ 368,967	Exhibit No. ES-114, Page 1, (M)
23	Benefits Administration	$ 7,515,336	$ 3,820,967	$ 1,622,760	$ 1,438,617	$ 14,397,680	Exhibit No. ES-301, Page 1, (M)
24	Total (Sum Ln 13 - Ln 23)	$ 29,503,098	$ 16,937,792	$ 6,464,515	$ 5,835,278	$ 58,740,683	

Exhibit No. ES-105

Corporate & Administrative Labor Savings Exhibit

Eversource Energy Service Company

Eversource Energy Service Company
Corporate & Administrative Labor Savings Exhibit

	(A)	Savings (B) 2012	(C) 2013	(D) 2014	(E) 2015	(F) Total
1	Employee Reductions	200	57	77	49	
2	Cumulative Employee Reductions	200	257	334	383	
3	Total Corporate & Administrative Labor Savings	$ 9,714,641 (a)	$ 36,129,496 (b)	$ 45,979,080 (c)	$ 57,241,954 (d)	
4	Capitalization Rate (e)	13.40%	12 84%	13.77%	14.32%	
5	Total O&M Savings (Ln 3*(1-Ln4))	$ 8,412,879	$ 31,490,219	$ 39,647,761	$ 49,044,906	
6	Total Capitalized Savings (Ln 3-Ln 5)	$ 1,301,762	$ 4,639,277	$ 6,331,319	$ 8,197,048	
7	Depreciation Rate (f)	3.26%	3 32%	3.22%	3.30%	
8	Return + Depreciation Rate + Property Tax Rate (g)	17.38%	17 22%	16.48%	16.66%	
	Capitalized Savings adjusted for Depreciation					
9	2012	$ 1,301,762	$ 1,258,568 (h)	$ 1,219,278 (i)	$ 1,177,094 (k)	
10	2013		$ 4,639,277	$ 4,489,892 (j)	$ 4,338,137 (l)	
11	2014			$ 6,331,319	$ 6,122,386 (m)	
12	2015				$ 8,197,048	
13	Total (Sum Ln 9- Ln 12)	$ 1,301,762	$ 5,897,845	$ 12,040,490	$ 19,834,664	
14	Revenue Requirements for the Capitalized Accounts (Ln 8 * Ln 13)	$ 226,288	$ 1,015,372	$ 1,984,273	$ 3,304,455	
15	Labor Savings and Revenue Requirements (Ln 5 + Ln 14)	$ 8,639,167 (n)	$ 32,505,591 (n)	$ 41,632,034 (n)	$ 39,262,021 (o)	$ 122,038,813

	(G) Allocation to Transmission:	(H) Allocation %	(I) = (B), Ln 15 *(H) 2012	(J)= (C), Ln 15 *(H) 2013	(K)= (D), Ln 15 *(H) 2014	(L)= (E), Ln 15 *(H) 2015	(M)= (I) + (J) + (K) + (L) Total
16	CL&P	13.06% (p)	$ 1,128,275	$ 4,245,230	$ 5,437,144	$ 5,127,620	$ 15,938,269
17	NSTAR Electric	6.64% (p)	$ 573,641	$ 2,158,371	$ 2,764,367	$ 2,606,998	$ 8,103,377
18	PSNH	2.82% (p)	$ 243,625	$ 916,658	$ 1,174,023	$ 1,107,189	$ 3,441,495
19	WMECO	2.50% (p)	$ 215,979	$ 812,640	$ 1,040,801	$ 981,551	$ 3,050,970
20	**Total Transmission (Sum Ln 16- Ln 19)**	25.02%	$ 2,161,520	$ 8,132,899	$ 10,416,335	$ 9,823,358	$ 30,534,111

(a) Exhibit No. ES-105, Page 2, Line 6 (F)
(b) Exhibit No. ES-105, Page 2, Line 12 (F)
(c) Exhibit No. ES-105, Page 2, Line 18 (F)
(d) Exhibit No. ES-105, Page 2, Line 24 (F)
(e) Capitalization Rate represents the portion of Corporate & Administrative Labor costs which were included in capitalized FERC accounts in the given year based on queries of Eversource accounting database.
(f) Depreciation Rate is calculated using Depreciation Expense from FERC Form 1, p336, Ln 12 divided by Net Utility Plant from FERC Form 1, p 110, Ln 6.
(g) Return Rate calculation is consistent with method as filed in the PTO AC Annual Informational Filing; return on equity (ROE) component is based on Eversource Distribution companies allowed ROE to be consistent with the merger cost/savings report submitted for state regulatory purposes. Depreciation Rate component see (f) above. Property Tax Rate component is calculated as Property Tax Expense divided by Net Utility Plant from FERC Form 1, p 110, Ln 6.
(h) Capitalized Savings, adjusted for Depreciation is calculated as (B), Ln 6 * (1-(C), Ln 7)
(i) Capitalized Savings, adjusted for Depreciation is calculated as (B), Ln 6 * (1-(D), Ln 7), for number of periods since initial savings
(j) Capitalized Savings, adjusted for Depreciation is calculated as (C), Ln 6 * (1-(D), Ln 7)
(k) Capitalized Savings, adjusted for Depreciation is calculated as (B), Ln 6 * (1-(E), Ln 7), for number of periods since initial savings
(l) Capitalized Savings, adjusted for Depreciation is calculated as (C), Ln 6 * (1-(E), Ln 7), for number of periods since initial savings
(m) Capitalized Savings, adjusted for Depreciation is calculated as (D), Ln 6 * (1-(E), Ln 7)
(n) Exhibit No. ES-103, Page 4, Line 1
(o) Annual savings multiplied by .75 to prorate and only include savings through September 30, 2015.
(p) Source is Exhibit No. ES-116

Eversource Energy Service Company
Corporate & Administrative Labor Savings Exhibit

	(A)	(B)	(C)	(D)	(E)	(F)	
		2012 Savings					
	Company	**Employees**	**Current year Savings**	**Annualized Savings**	**Cumulative Employees**	**Cumulative Savings**	**Reference**
1	NUSCO*	192	$ 9,367,504	$ 28,134,224	192	$ 9,367,504	Exhibit No. ES-105, Page 3, Line 26 (B)
2	CL&P	2	$ 40,432	$ 300,004	2	$ 40,432	Exhibit No. ES-105, Page 4, Line 26 (B)
3	NSTAR Electric	1	$ 217,973	$ 366,960	1	$ 217,973	Exhibit No. ES-105, Page 5, Line 26 (B)
4	PSNH	3	$ 43,330	$ 504,745	3	$ 43,330	Exhibit No. ES-105, Page 6, Line 26 (B)
5	WMECO	2	$ 45,402	$ 281,479	2	$ 45,402	Exhibit No. ES-105, Page 7, Line 26 (B)
6	Total(Ln 1- Ln 5):	200	$ 9,714,641	$ 29,587,412	200	$ 9,714,641	
		2013 Savings					
	Company	**Employees**	**Current year Savings**	**Annualized Savings**	**Cumulative Employees**	**Cumulative Savings**	
7	NUSCO*	56	$ 5,556,441	$ 8,692,267	248	$ 34,534,692	Exhibit No. ES-105, Page 3, Line 26 (C)
8	CL&P	0	$ -	$ -	2	$ 309,004	Exhibit No. ES-105, Page 4, Line 26 (C)
9	NSTAR Electric	1	$ 98,020	$ 198,558	2	$ 475,989	Exhibit No. ES-105, Page 5, Line 26 (C)
10	PSNH	0	$ -	$ -	3	$ 519,888	Exhibit No. ES-105, Page 6, Line 26 (C)
11	WMECO	0	$ -	$ -	2	$ 289,923	Exhibit No. ES-105, Page 7, Line 26 (C)
12	Total(Ln 7- Ln 11):	57	$ 5,654,461	$ 8,890,825	257	$ 36,129,496	
		2014 Savings					
	Company	**Employees**	**Current year Savings**	**Annualized Savings**	**Cumulative Employees**	**Cumulative Savings**	
13	NUSCO*	75	$ 5,326,328	$ 11,162,438	323	$ 44,126,960	Exhibit No. ES-105, Page 3, Line 26 (D)
14	CL&P	0	$ -	$ -	2	$ 318,274	Exhibit No. ES-105, Page 4, Line 26 (D)
15	NSTAR Electric	0	$ -	$ -	2	$ 593,823	Exhibit No. ES-105, Page 5, Line 26 (D)
16	PSNH	1	$ 34,888	$ 207,254	4	$ 570,373	Exhibit No. ES-105, Page 6, Line 26 (D)
17	WMECO	1	$ 71,029	$ 207,320	3	$ 369,651	Exhibit No. ES-105, Page 7, Line 26 (D)
18	Total(Ln 13- Ln 17):	77	$ 5,432,245	$ 11,577,012	334	$ 45,979,080	
		2015 Savings					
	Company	**Employees**	**Current year Savings**	**Annualized Savings**	**Cumulative Employees**	**Cumulative Savings**	
19	NUSCO*	49	$ 3,554,391	$ 6,866,554	372	$ 55,016,354	Exhibit No. ES-105, Page 3, Line 26 (E)
20	CL&P	0	$ -	$ -	2	$ 327,822	Exhibit No. ES-105, Page 4, Line 26 (E)
21	NSTAR Electric	0	$ -	$ -	2	$ 611,637	Exhibit No. ES-105, Page 5, Line 26 (E)
22	PSNH	0	$ -	$ -	4	$ 765,021	Exhibit No. ES-105, Page 6, Line 26 (E)
23	WMECO	0	$ -	$ -	3	$ 521,120	Exhibit No. ES-105, Page 7, Line 26 (E)
24	Total(Ln 19- Ln 23):	49	$ 3,554,391	$ 6,866,554	383	$ 57,241,954	

*On July 1, 2015, Northeast Utilities Service Company's (NUSCO) legal name was changed to Eversource Energy Service Company.

NUSCO Shared Services*
Corporate & Administrative Labor Savings Exhibit

	(A)	(B)		(C)		(D)		(E)	
	Current Year	**2012**		**2013**		**2014**		**2015** (a)	
1	Merger Related Employee Reductions	173		40		18		2	
2	Current Year Merger Reduction Salary Savings	$ 5,484,266		$ 2,937,944		$ 692,321		$ 148,886	
3	Current Year Merger Reduction Benefits Savings	$ 2,287,714		$ 1,206,412		$ 334,467		$ 77,084	
4	Total Current Year Merger Reduction Savings (Ln 2 + Ln 3)	$ 7,771,979	(b)	$ 4,144,356	(c)	$ 1,026,788	(d)	$ 225,970	(e)
5	Annual Merger Reduction Salary Savings	$ 16,626,792		$ 4,263,306		$ 1,674,855		$ 148,886	
6	Annual Merger Reduction Loader Savings	$ 7,036,390		$ 1,777,979		$ 857,148		$ 77,084	
7	Total Annual Merger Reduction Savings (Ln 5 + Ln 6)	$ 23,663,182	(f)	$ 6,041,285	(g)	$ 2,532,003	(h)	$ 225,970	(i)
8	Attrition Related Reductions	19	(j)	16	(k)	57	(l)	47	(m)
9	Salary (n)	$ 91,133		$ 86,663		$ 88,168		$ 88,485	
10	Current Year Attrition Salary Savings	$ 649,323	(o)	$ 693,304	(o)	$ 2,512,788	(p)	$ 2,079,398	(p)
11	Current Year Attrition Benefits Savings	$ 283,519	(q)	$ 328,790	(q)	$ 1,440,451	(r)	$ 1,005,695	(r)
12	Total Current Year Attrition Savings (Ln 10 + Ln 11)	$ 932,842		$ 1,022,094		$ 3,953,239		$ 3,085,093	
13	Annual Salary Attrition Savings (Ln 8 * Ln 9)	$ 1,731,527		$ 1,386,608		$ 5,025,576		$ 4,158,795	
14	Annual Attrition Benefits Savings	$ 756,051	(q)	$ 657,580	(q)	$ 2,880,902	(r)	$ 2,011,390	(r)
15	Total Annual Attrition Savings (Ln 13 + Ln 14)	$ 2,487,578		$ 2,044,188		$ 7,906,478		$ 6,170,185	
16	Total Current Year Employee Savings (Ln 1 + Ln 8)	192		56		75		49	
17	Total Current Year Salary Savings (Ln 2 + Ln 10)	$ 6,133,588		$ 3,631,248		$ 3,205,109		$ 2,228,284	
18	Total Current Year Incentive Pay Savings	$ 662,683	(s)	$ 389,991	(s)	$ 346,300	(t)	$ 243,329	(t)
19	Total Current Year Benefit Savings (Ln 3 + Ln 11)	$ 2,571,233		$ 1,535,202		$ 1,774,918		$ 1,082,779	
20	Total Current Year Savings (Ln 17 + Ln 18 + Ln 19)	$ 9,367,504		$ 5,556,441		$ 5,326,328		$ 3,554,391	
21	Annual Salary Employee Savings (Ln 5 + Ln 13)	$ 18,358,319		$ 5,649,914		$ 6,700,431		$ 4,307,681	
22	Annual Incentive Pay Savings	$ 1,983,464	(s)	$ 606,794	(s)	$ 723,957	(t)	$ 470,399	(t)
23	Annual Employee Benefits Savings (Ln 6 + Ln 14)	$ 7,792,441		$ 2,435,559		$ 3,738,050		$ 2,088,474	
24	Total Annual Employee Savings (Ln 21 + Ln 22 + Ln 23)	$ 28,134,224		$ 8,692,267		$ 11,162,438		$ 6,866,554	
	Cumulative Total								
25	Cumulative employee reductions (PY Ln 25 + CY Ln 16)	192		248		323		372	
26	**Cumulative labor savings with wage growth/inflation (PY Ln 24 + Ln 20 +3% Wage growth)**	**$ 9,367,504**	(u)	**$ 34,534,692**	(v)	**$ 44,126,960**	(w)	**$ 55,016,354**	(x)

*On July 1, 2015, Northeast Utilities Service Company's (NUSCO) legal name was changed to Eversource Energy Service Company.

(a) 2015 savings are calculated through September 30, 2015.
(b) Exhibit No. ES-105, Page 14, Ln 183 (M)
(c) Exhibit No. ES-105, Page 21, Ln 43 (M)
(d) Exhibit No. ES-105, Page 28, Ln 22 (L)
(e) Exhibit No. ES-105, Page 34, Ln 3 (L)
(f) Exhibit No. ES-105, Page 18, Ln 183 (T)
(g) Exhibit No. ES-105, Page 22, Ln 43 (T)
(h) Exhibit No. ES-105, Page 29, Ln 22 (S)
(i) Exhibit No. ES-105, Page 34, Ln 3 (S)
(j) Exhibit No. ES-105, Page 20, Ln 96 (C)
(k) Exhibit No. ES-105, Page 27, Ln 225 (C)
(l) Exhibit No. ES-105, Page 33, Ln 202 (C)
(m) Exhibit No. ES-105, Page 39, Ln 152 (C)
(n) Salary for 2012 and 2014 is based on average salary for shared services employee of the Legacy companies and for 2014 and 2015 is based on an average salary of offsetting hires.

(o) Exhibit No. ES-105, Page 8, Ln 13
(p) Exhibit No. ES-105, Page 9, Ln 13
(q) Exhibit No. ES-105, Page 8, Ln 19
(r) Exhibit No. ES-105, Page 9, Ln 19
(s) Exhibit No. ES-105, Page 8, Ln 16
(t) Exhibit No. ES-105, Page 9, Ln 16
(u) Cumulative labor savings: (B), Ln 20
(v) Cumulative labor savings is calculated by: 2012 Annual Attrition * (1+Wage Growth) + 2013 Year Savings.
(w) Cumulative labor savings is calculated by: 2012 + 2013 Annual Attrition * (1+Wage Growth) + 2014 Year Savings.
(x) Cumulative labor savings is calculated by: 2012 + 2013 & 2014 Annual Attrition * (1+Wage Growth) + 2015 Year Savings.

The Connecticut Light & Power Company
Corporate & Administrative Labor Savings Exhibit

	(A) Current Year	(B) 2012		(C) 2013		(D) 2014		(E) 2015 (a)	
1	Merger Related Employee Reductions	2		-		-		-	
2	Current Year Merger Reduction Salary Savings	$ 27,210		$ -		$ -		$ -	
3	Current Year Merger Reduction Benefits Savings	$ 10,281		$ -		$ -		$ -	
4	Total Current Year Merger Reduction Savings (Ln 2 + Ln 3)	$ 37,492	(b)	$ -		$ -		$ -	
5	Annual Merger Reduction Salary Savings	$ 201,607		$ -		$ -		$ -	
6	Annual Merger Reduction Loader Savings	$ 76,615		$ -		$ -		$ -	
7	Total Annual Merger Reduction Savings (Ln 5 + Ln 6)	$ 278,222	(c)	$ -		$ -		$ -	
8	Attrition Related Reductions	-		-		-		-	
9	Salary (d)	$ -		$ -		$ -		$ -	
10	Current Year Attrition Salary Savings ([Ln 8 * Ln 9] / 2)	$ -		$ -		$ -		$ -	
11	Current Year Attrition Benefits Savings (Ln 10*[Ln 29+Ln 32]+Ln 8*Ln 35 / 2)	$ -		$ -		$ -		$ -	
12	Total Current Year Attrition Savings (Ln 10 + Ln 11)	$ -		$ -		$ -		$ -	
13	Annual Salary Attrition Savings (Ln 8 * Ln 9)	$ -		$ -		$ -		$ -	
14	Annual Attrition Benefits Savings (Ln 10*[Ln 29+Ln 32]+Ln 8*Ln 35)	$ -		$ -		$ -		$ -	
15	Total Annual Attrition Savings (Ln 13 + Ln 14)	$ -		$ -		$ -		$ -	
16	Total Current Year Employee Savings (Ln 1 + Ln 8)	2		-		-		-	
17	Total Current Year Salary Savings (Ln 2 + Ln 10)	$ 27,210		$ -		$ -		$ -	
18	Total Current Year Incentive Pay Savings (e)	$ 2,940		$ -		$ -		$ -	
19	Total Current Year Benefit Savings (Ln 3 + Ln 11)	$ 10,281		$ -		$ -		$ -	
20	Total Current Year Savings (Ln 17 + Ln 18 + Ln 19)	$ 40,432		$ -		$ -		$ -	
21	Annual Salary Employee Savings (Ln 5 + Ln 13)	$ 201,607		$ -		$ -		$ -	
22	Annual Incentive Pay Savings (e)	$ 21,782		$ -		$ -		$ -	
23	Annual Employee Benefits Savings (Ln 6 + Ln 14)	$ 76,615		$ -		$ -		$ -	
24	Total Annual Employee Savings (Ln 21 + Ln 22 + Ln 23)	$ 300,004		$ -		$ -		$ -	
	Cumulative Total								
25	Cumulative employee reductions	2		2		2		2	
26	**Cumulative labor savings with wage growth/inflation (PY Ln 24 + Ln 20)**	**$ 40,432**	(f)	**$ 309,004**	(g)	**$ 318,274**	(h)	**$ 327,822**	(i)

(a) 2015 savings are calculated through September 30, 2015.
(b) Exhibit No. ES-105, Page 14, Ln 184 (M)
(c) Exhibit No. ES-105, Page 18, Ln 184 (T)
(d) Salary for 2012 and 2014 is based on average salary for shared services employee of the Legacy companies and for 2014 and 2015 is based on an average salary of offsetting hires.
(e) Exhibit No. ES-105, Page 10, Ln 10
(f) Cumulative labor savings: (B), Ln 20
(g) Cumulative labor savings is calculated by: 2012 Annual Attrition * (1+Wage Growth) + 2013 Year Savings.
(h) Cumulative labor savings is calculated by: 2012 + 2013 Annual Attrition * (1+Wage Growth) + 2014 Year Savings.
(i) Cumulative labor savings is calculated by: 2012 + 2013 & 2014 Annual Attrition * (1+Wage Growth) + 2015 Year Savings.

NSTAR Electric Company
Corporate & Administrative Labor Savings Exhibit

	(A) Current Year	(B) 2012		(C) 2013		(D) 2014		(E) 2015 (a)	
1	Merger Related Employee Reductions	1		1		-		-	
2	Current Year Merger Reduction Salary Savings	$ 145,989		$ 64,398		$ -		$ -	
3	Current Year Merger Reduction Benefits Savings	$ 56,211		$ 26,705		$ -		$ -	
4	Total Current Year Merger Reduction Savings (Ln 2 + Ln 3)	$ 202,200	(b)	$ 91,104	(c)	$ -		$ -	
5	Annual Merger Reduction Salary Savings	$ 249,000		$ 131,315		$ -		$ -	
6	Annual Merger Reduction Loader Savings	$ 91,058		$ 53,140		$ -		$ -	
7	Total Annual Merger Reduction Savings (Ln 5 + Ln 6)	$ 340,058	(d)	$ 184,455	(e)	$ -		$ -	
8	Attrition Related Reductions	-		-		-		-	
9	Salary (f)	$ -		$ -		$ -		$ -	
10	Current Year Attrition Salary Savings ([Ln 8 * Ln 9] / 2)	$ -		$ -		$ -		$ -	
11	Current Year Attrition Benefits Savings (Ln 10*[Ln 29+Ln 32]+Ln 8*Ln 35 / 2)	$ -		$ -		$ -		$ -	
12	Total Current Year Attrition Savings (Ln 10 + Ln 11)	$ -		$ -		$ -		$ -	
13	Annual Salary Attrition Savings (Ln 8 * Ln 9)	$ -		$ -		$ -		$ -	
14	Annual Attrition Benefits Savings (Ln 10*[Ln 29+Ln 32]+Ln 8*Ln 35)	$ -		$ -		$ -		$ -	
15	Total Annual Attrition Savings (Ln 13 + Ln 14)	$ -		$ -		$ -		$ -	
16	Total Current Year Employee Savings (Ln 1 + Ln 8)	1		1		-		-	
17	Total Current Year Salary Savings (Ln 2 + Ln 10)	$ 145,989		$ 64,398		$ -		$ -	
18	Total Current Year Incentive Pay Savings (g)	$ 15,773		$ 6,916		$ -		$ -	
19	Total Current Year Benefit Savings (Ln 3 + Ln 11)	$ 56,211		$ 26,705		$ -		$ -	
20	Total Current Year Savings (Ln 17 + Ln 18 + Ln 19)	$ 217,973		$ 98,020		$ -		$ -	
21	Annual Salary Employee Savings (Ln 5 + Ln 13)	$ 249,000		$ 131,315		$ -		$ -	
22	Annual Incentive Pay Savings (g)	$ 26,902		$ 14,103		$ -		$ -	
23	Annual Employee Benefits Savings (Ln 6 + Ln 14)	$ 91,058		$ 53,140		$ -		$ -	
24	Total Annual Employee Savings (Ln 21 + Ln 22 + Ln 23)	$ 366,960		$ 198,558		$ -		$ -	
	Cumulative Total								
25	Cumulative employee reductions	1		2		2		2	
26	**Cumulative labor savings with wage growth/inflation (PY Ln 24 + Ln 20)**	**$ 217,973**	(h)	**$ 475,989**	(i)	**$ 593,823**	(j)	**$ 611,637**	(k)

(a) 2015 savings are calculated through September 30, 2015.
(b) Exhibit No. ES-105, Page 14, Ln 185 (M)
(c) Exhibit No. ES-105, Page 21, Ln 45 (M)
(d) Exhibit No. ES-105, Page 18, Ln 185 (T)
(e) Exhibit No. ES-105, Page 22, Ln 45 (T)
(f) Salary for 2012 and 2014 is based on average salary for shared services employee of the Legacy companies and for 2014 and 2015 is based on an average salary of offsetting hires.
(g) Exhibit No. ES-105, Page 10, Ln 14
(h) Cumulative labor savings: (B), Ln 20
(i) Cumulative labor savings is calculated by: 2012 Annual Attrition * (1+Wage Growth) + 2013 Year Savings.
(j) Cumulative labor savings is calculated by: 2012 + 2013 Annual Attrition * (1+Wage Growth) + 2014 Year Savings.
(k) Cumulative labor savings is calculated by: 2012 + 2013 & 2014 Annual Attrition * (1+Wage Growth)+ 2015 Year Savings.

Public Service Company of New Hampshire
Corporate & Administrative Labor Savings Exhibit

	(A) Current Year	(B) 2012		(C) 2013		(D) 2014		(E) 2015 (a)	
1	Merger Related Employee Reductions	3		-		1		-	
2	Current Year Merger Reduction Salary Savings	$ 27,051		$ -		$ 23,632		$ -	
3	Current Year Merger Reduction Benefits Savings	$ 13,356		$ -		$ 8,728		$ -	
4	Total Current Year Merger Reduction Savings (Ln 2 + Ln 3)	$ 40,407	(b)	$ -		$ 32,359	(c)	$ -	
5	Annual Merger Reduction Salary Savings	$ 333,289		$ -		$ 141,403		$ -	
6	Annual Merger Reduction Loader Savings	$ 135,447		$ -		$ 50,718		$ -	
7	Total Annual Merger Reduction Savings (Ln 5 + Ln 6)	$ 468,736	(d)	$ -		$ 192,121	(e)	$ -	
8	Attrition Related Reductions	-		-		-		-	
9	Salary (f)	$ -		$ -		$ -		$ -	
10	Current Year Attrition Salary Savings ([Ln 8 * Ln 9] / 2)	$ -		$ -		$ -		$ -	
11	Current Year Attrition Benefits Savings (Ln 10*[Ln 29+Ln 32]+Ln 8*Ln 35 / 2)	$ -		$ -		$ -		$ -	
12	Total Current Year Attrition Savings (Ln 10 + Ln 11)	$ -		$ -		$ -		$ -	
13	Annual Salary Employee Savings (Ln 8 * Ln 9)	$ -		$ -		$ -		$ -	
14	Annual Employee Benefits Savings (Ln 10*[Ln 29+Ln 32]+Ln 8*Ln 35)	$ -		$ -		$ -		$ -	
15	Total Annual Attrition Savings (Ln 13 + Ln 14)	$ -		$ -		$ -		$ -	
16	Total Current Year Employee Savings (Ln 1 + Ln 8)	3		-		1		-	
17	Total Current Year Salary Savings (Ln 2 + Ln 10)	$ 27,051		$ -		$ 23,632		$ -	
18	Total Current Year Incentive Pay Savings (g)	$ 2,923		$ -		$ 2,529		$ -	
19	Total Current Year Benefit Savings (Ln 3 + Ln 11)	$ 13,356		$ -		$ 8,728		$ -	
20	Total Current Year Savings (Ln 17 + Ln 18 + Ln 19)	$ 43,330		$ -		$ 34,888		$ -	
21	Annual Salary Attrition Savings (Ln 5 + Ln 13)	$ 333,289		$ -		$ 141,403		$ -	
22	Annual Incentive Pay Savings (g)	$ 36,009		$ -		$ 15,133		$ -	
23	Annual Attrition Benefits Savings (Ln 6 + Ln 14)	$ 135,447		$ -		$ 50,718		$ -	
24	Total Annual Employee Savings (Ln 21 + Ln 22 + Ln 23)	$ 504,745		$ -		$ 207,254		$ -	
	Cumulative Total								
25	Cumulative employee reductions	3		3		4		4	
26	**Cumulative labor savings with wage growth/inflation (PY Ln 24 + Ln 20)**	**$ 43,330**	(h)	**$ 519,888**	(i)	**$ 570,373**	(j)	**$ 765,021**	(k)

(a) 2015 savings are calculated through September 30, 2015.
(b) Exhibit No. ES-105, Page 14, Ln 186 (M)
(c) Exhibit No. ES-105, Page 28, Ln 25 (L)
(d) Exhibit No. ES-105, Page 18, Ln 186 (T)
(e) Exhibit No. ES-105, Page 29, Ln 25 (S)
(f) Salary for 2012 and 2014 is based on average salary for shared services employee of the Legacy companies and for 2014 and 2015 is based on an average salary of offsetting hires.
(g) Exhibit No. ES-105, Page 10, Ln 18
(h) Cumulative labor savings: (B), Ln 20
(i) Cumulative labor savings is calculated by: 2012 Annual Attrition * (1+Wage Growth) + 2013 Year Savings.
(j) Cumulative labor savings is calculated by: 2012 + 2013 Annual Attrition * (1+Wage Growth) + 2014 Year Savings.
(k) Cumulative labor savings is calculated by: 2012 + 2013 & 2014 Annual Attrition * (1+Wage Growth) + 2015 Year Savings.

Western Massachusetts Electric Company
Corporate & Administrative Labor Savings Exhibit

	(A) Current Year	(B) 2012		(C) 2013		(D) 2014		(E) 2015 (a)	
1	Merger Related Employee Reductions	2		-		1		-	
2	Current Year Merger Reduction Salary Savings	$ 30,321		$ -		$ 49,411		$ -	
3	Current Year Merger Reduction Benefits Savings	$ 11,805		$ -		$ 16,314		$ -	
4	Total Current Year Merger Reduction Savings (Ln 2 + Ln 3)	$ 42,126	(b)	$ -		$ 65,725	(c)	$ -	
5	Annual Merger Reduction Salary Savings	$ 189,283		$ -		$ 145,444		$ -	
6	Annual Merger Reduction Loader Savings	$ 71,746		$ -		$ 46,263		$ -	
7	Total Annual Merger Reduction Savings (Ln 5 + Ln 6)	$ 261,029	(d)	$ -		$ 191,707	(e)	$ -	
8	Attrition Related Reductions	-		-		-		-	
9	Salary (f)	$ -		$ -		$ -		$ -	
10	Current Year Attrition Salary Savings ([Ln 8 * Ln 9] / 2)	$ -		$ -		$ -		$ -	
11	Current Year Attrition Benefits Savings (Ln 10*[Ln 29+Ln 32]+Ln 8*Ln 35 / 2)	$ -		$ -		$ -		$ -	
12	Total Current Year Attrition Savings (Ln 10 + Ln 11)	$ -		$ -		$ -		$ -	
13	Annual Salary Attrition Savings (Ln 8 * Ln 9)	$ -		$ -		$ -		$ -	
14	Annual Attrition Benefits Savings (Ln 10*[Ln 29+Ln 32]+Ln 8*Ln 35)	$ -		$ -		$ -		$ -	
15	Total Annual Attrition Savings (Ln 13 + Ln 14)	$ -		$ -		$ -		$ -	
16	Total Current Year Employee Savings (Ln 1 + Ln 8)	2		-		1		-	
17	Total Current Year Salary Savings (Ln 2 + Ln 10)	$ 30,321		$ -		$ 49,411		$ -	
18	Total Current Year Incentive Pay Savings (g)	$ 3,276		$ -		$ 5,304		$ -	
19	Total Current Year Benefit Savings (Ln 3 + Ln 11)	$ 11,805		$ -		$ 16,314		$ -	
20	Total Current Year Savings (Ln 17 + Ln 18 + Ln 19)	$ 45,402		$ -		$ 71,029		$ -	
21	Annual Salary Employee Savings (Ln 5 + Ln 13)	$ 189,283		$ -		$ 145,444		$ -	
22	Annual Incentive Pay Savings (g)	$ 20,450		$ -		$ 15,613		$ -	
23	Annual Employee Benefits Savings (Ln 6 + Ln 14)	$ 71,746		$ -		$ 46,263		$ -	
24	Total Annual Employee Savings (Ln 21 + Ln 22 + Ln 23)	$ 281,479		$ -		$ 207,320		$ -	
	Cumulative Total								
25	Cumulative employee reductions	2		2		3		3	
26	**Cumulative labor savings with wage growth/inflation (PY Ln 24 + Ln 20)**	**$ 45,402**	(h)	**$ 289,923**	(i)	**$ 369,651**	(j)	**$ 521,120**	(k)

(a) 2015 savings are calculated through September 30, 2015.
(b) Exhibit No. ES-105, Page 14, Ln 187 (M)
(c) Exhibit No. ES-105, Page 28, Ln 26 (L)
(d) Exhibit No. ES-105, Page 18, Ln 187 (T)
(e) Exhibit No. ES-105, Page 29, Ln 26 (S)
(f) Salary for 2012 and 2014 is based on average salary for shared services employee of the Legacy companies and for 2014 and 2015 is based on an average salary of offsetting hires.
(g) Exhibit No. ES-105, Page 10, Ln 22
(h) Cumulative labor savings: (B), Ln 20
(i) Cumulative labor savings is calculated by: 2012 Annual Attrition * (1+Wage Growth) + 2013 Year Savings
(j) Cumulative labor savings is calculated by: 2012 + 2013 Annual Attrition * (1+Wage Growth) + 2014 Year Savings
(k) Cumulative labor savings is calculated by: 2012 + 2013 & 2014 Annual Attrition * (1+Wage Growth) + 2015 Year Savings

Eversource Energy Service Company
Corporate & Administrative Labor Savings Exhibit
Calculation of Employee Savings-NUSCO

2012

Ln	(A)	(B)	(C)
	Attrition Related Reductions		
1	Number (a)		19
2	Annual Salary (b)	$	91,133
	Benefits/Taxes/Pension Costs:		
3	Weighted Average Benefits Loader Rate (c)		20.41%
4	Weighted Average Payroll Tax Rate-NUSCO, CL&P, NSTAR (d)		8.04%
5	Weighted Average Payroll Tax Rate-PSNH (d)		8.04%
6	Weighted Average Payroll Tax Rate-WMECO (d)		8.04%
7	Weighted Average Pension & PBOP Service Cost (e)	$	13,861
8	Incentive Pay Percent (f)		10%
9	Pay Incentive with Tax-NUSCO, CL&P, NSTAR (Ln 8*(1+Ln 4))		10.804%
10	Pay Incentive with Tax-PSNH (Ln *(1+ Ln 5))		10.804%
11	Pay Incentive with Tax-WMECO (Ln *(1+ Ln 5))		10.804%

Ln		CURRENT YEAR (CY)	ANNUALIZED (A)
12	Annual Salary Attrition(Ln 1 * Ln 2)	$ 1,731,527	$ 1,731,527
13	Attrition Salary Savings (Ln 12/2) *9/12	$ 649,323	$ 1,731,527
14	Merger Reduction Salary Savings (g)	$ 5,484,266	$ 16,626,792
15	Salary Savings (Ln 13+ Ln 14)	$ 6,133,588	$ 18,358,319
16	Incentive Pay Savings (Ln 15* Ln 9)	$ 662,683	$ 1,983,464
17	Benefits & PR Tax (Ln 13*(Ln 3+4)	$ 184,756	$ 492,684
18	PBOP (Ln 1* Ln 7/12*9/2)	$ 98,763	$ 263,367
19	Attrition Benefits Savings (Ln 17+ Ln 18)	$ 283,519	$ 756,051
20	Merger Reduction Benefits Savings (g)	$ 2,287,714	$ 7,036,390
21	Benefit Savings (Ln 19+ Ln 20)	$ 2,571,233	$ 7,792,441
22	**Total Employee Savings (Sum Ln 15+ Ln 16+ Ln 21)**	**$ 9,367,504**	**$ 28,134,224**

2013

Ln	(D)	(E)	(F)
	Attrition Related Reductions		
1	Number (h)		16
2	Annual Salary (b)	$	86,663
	Benefits/Taxes/Pension Costs:		
3	Weighted Average Benefits Loader Rate (c)		19.24%
4	Weighted Average Payroll Tax Rate-NUSCO, CL&P, NSTAR (d)		7.40%
5	Weighted Average Payroll Tax Rate-PSNH (d)		7.40%
6	Weighted Average Payroll Tax Rate-WMECO (d)		7.40%
7	Weighted Average Pension & PBOP Service Cost (e)	$	18,009
8	Incentive Pay Percent (f)		10.00%
9	Pay Incentive with Tax-NUSCO, CL&P, NSTAR (Ln 8*(1+Ln 4))		10.74%
10	Pay Incentive with Tax-PSNH (Ln *(1+ Ln 5))		10.74%
11	Pay Incentive with Tax-WMECO (Ln *(1+ Ln 5))		10.74%

Ln		CURRENT YEAR (CY)	ANNUALIZED (A)
12	Annual Salary Attrition(Ln 1 * Ln 2)	$ 1,386,608	$ 1,386,608
13	Attrition Salary Savings (Ln 12/2)	$ 693,304	$ 1,386,608
14	Merger Reduction Salary Savings (i)	$ 2,937,944	$ 4,263,306
15	Salary Savings (Ln 13+ Ln 14)	$ 3,631,248	$ 5,649,914
16	Incentive Pay Savings (Ln 15* Ln 9)	$ 389,991	$ 606,794
17	Benefits & PR Tax (Ln 13*(Ln 3+4)	$ 184,716	$ 369,432
18	PBOP (Ln 1* Ln 7/2)	$ 144,074	$ 288,148
19	Attrition Benefits Savings (Ln 17+ Ln 18)	$ 328,790	$ 657,580.15
20	Merger Reduction Benefits Savings (i)	$ 1,206,412	$ 1,777,979
21	Benefit Savings (Ln 19+ Ln 20)	$ 1,535,202	$ 2,435,559
22	**Total Employee Savings (Sum Ln 15+ Ln 16+ Ln 21)**	**$ 5,556,441**	**$ 8,692,267**

(a) Exhibit No. ES-105, Page 20, Line 96 (C)
(b) Salary for 2012 and 2014 is based on average salary for shared services employee of the Legacy companies and for 2014 and 2015 is based on an average salary of offsetting hires.
(c) Weighted Average Benefit Loader Rate was calculated as the ratio of health benefit costs to total labor costs in the given year based on queries of Eversource accounting database.
(d) Weighted Average Payroll Tax Rate was calculated as the ratio of employee payroll taxes to total labor costs in the given year based on queries of Eversource accounting database.
(e) Weighted Average Pension and PBOP Service Costs is the average pension and postretirement benefits other than pension (PBOP) cost per employee based on data from Eversource actuarial reports for the given year.

(f) Incentive Pay Percent is based on an average target incentive pay in the given year.
(g) Exhibit No. ES-105, Page 14(CY), Page 18(A), Line 183
(h) Exhibit No. ES-105, Page 27, Line 225 (C)
(i) Exhibit No. ES-105, Page 21(CY), Page 22(A), Line 43

Eversource Energy Service Company
Corporate & Administrative Labor Savings Exhibit
Calculation of Employee Savings-NUSCO

2014

Ln	(A)	(B)	(C)
	Attrition Related Reductions		
1	Number (a)		57
2	Annual Salary (b)		$ 88,168.00
	Benefits/Taxes/Pension Costs:		
3	Weighted Average Benefits Loader Rate (c)		33.76%
4	Weighted Average Payroll Tax Rate-NUSCO, CL&P, NSTAR (d)		8.05%
5	Weighted Average Payroll Tax Rate-PSNH (d)		7.02%
6	Weighted Average Payroll Tax Rate-WMECO (d)		7.35%
7	Weighted Average Pension & PBOP Service Cost (e)		$ 13,686.64
8	Incentive Pay Percent (f)		10.00%
9	Pay Incentive with Tax-NUSCO, CL&P, NSTAR (Ln 8*(1+Ln 4))		10.80%
10	Pay Incentive with Tax-PSNH (Ln *(1+ Ln 5))		10.70%
11	Pay Incentive with Tax-WMECO (Ln *(1+ Ln 5))		10.74%
		CURRENT YEAR (CY)	**ANNUALIZED (A)**
12	Annual Salary Attrition(Ln 1 * Ln 2)	$ 5,025,576	$ 5,025,576
13	Attrition Salary Savings (Ln 12/2)	$ 2,512,788	$ 5,025,576
14	Merger Reduction Salary Savings (g)	$ 692,321	$ 1,674,855
15	Salary Savings (Ln 13+ Ln 14)	$ 3,205,109	$ 6,700,431
16	Incentive Pay Savings (Ln 15 * Ln 9)	$ 346,300	$ 723,957
17	Benefits & PR Tax (Ln 13 *(Ln 3+ Ln 4)	$ 1,050,382	$ 2,100,764
18	PBOP (Ln 1* Ln 7 / 2)	$ 390,069	$ 780,139
19	Attrition Benefits Savings (Ln 17 + Ln 18)	$ 1,440,451	$ 2,880,902
20	Merger Reduction Benefits Savings (g)	$ 334,467	$ 857,148
21	Benefit Savings (Ln 19+ Ln 20)	$ 1,774,918	$ 3,738,050
22	**Total Employee Savings (Sum Ln 15+16+21)**	**$ 5,326,328**	**$ 11,162,438**

2015

Ln	(D)	(E)	(F)
	Attrition Related Reductions		
1	Number (h)		47
2	Annual Salary (b)		$ 88,485
	Benefits/Taxes/Pension Costs:		
3	Weighted Average Benefits Loader Rate (c)		21.09%
4	Weighted Average Payroll Tax Rate-NUSCO, CL&P, NSTAR (d)		9.20%
5	Weighted Average Payroll Tax Rate-PSNH (d)		9.20%
6	Weighted Average Payroll Tax Rate-WMECO (d)		9.20%
7	Weighted Average Pension & PBOP Service Cost (e)		$ 15,991
8	Incentive Pay Percent (f)		10.00%
9	Pay Incentive with Tax-NUSCO, CL&P, NSTAR (Ln 8*(1+Ln 4))		10.92%
10	Pay Incentive with Tax-PSNH (Ln *(1+ Ln 5))		10.92%
11	Pay Incentive with Tax-WMECO (Ln *(1+ Ln 5))		10.92%
		CURRENT YEAR (CY)	**ANNUALIZED (A)**
12	Annual Salary Attrition(Ln 1 * Ln 2)	$ 4,158,795	$ 4,158,795
13	Attrition Salary Savings (Ln 12 / 2)	$ 2,079,398	$ 4,158,795
14	Merger Reduction Salary Savings (i)	$ 148,886	$ 148,886
15	Salary Savings (Ln 13 + Ln 14)	$ 2,228,284	$ 4,307,681
16	Incentive Pay Savings (Ln 15 * Ln 9)	$ 243,329	$ 470,399
17	Benefits & PR Tax (Ln 13 *(Ln 3 + Ln 4)	$ 629,904	$ 1,259,808
18	PBOP (Ln 1 * Ln 7 / 2)	$ 375,791	$ 751,582
19	Attrition Benefits Savings (Ln 17 + Ln 18)	$ 1,005,695	$ 2,011,390
20	Merger Reduction Benefits Savings (i)	$ 77,084	$ 77,084
21	Benefit Savings (Ln 19 + Ln 20)	$ 1,082,779	$ 2,088,474
22	**Total Employee Savings (Sum Ln 15+16+21)**	**$ 3,554,391**	**$ 6,866,554**

(a) Exhibit No. ES-105, Page 33, Line 202 (C)
(b) Salary for 2012 and 2014 is based on average salary for shared services employee of the Legacy companies and for 2014 and 2015 is based on an average salary of offsetting hires.
(c) Weighted Average Benefit Loader Rate was calculated as the ratio of health benefit costs to total labor costs in the given year based on queries of Eversource accounting database.
(d) Weighted Average Payroll Tax Rate was calculated as the ratio of employee payroll taxes to total labor costs in the given year based on queries of Eversource accounting database.
(e) Weighted Average Pension and PBOP Service Costs is the average pension and postretirement benefits other than pension (PBOP) cost per employee based on data from Eversource actuarial reports for the given year.
(f) Incentive Pay Percent is based on an average target incentive pay in the given year.
(g) Exhibit No. ES-105, Page 28(CY), Page 29(A), Line 22
(h) Exhibit No. ES-105, Page 39, Line 152 (C)
(i) Exhibit No. ES-105, Page 34(CY), Page 35(A), Line 3

Eversource Energy Service Company
Corporate & Administrative Labor Savings Exhibit
Calculation of Employee Savings-CL&P, NSTAR, PSNH, & WMECO

2012

Ln	(A)	(B)	(C)
1	**Benefits/Taxes/Pension Costs:**		
2	Weighted Average Payroll Tax Rate-NUSCO, CL&P, NSTAR (a)		8.04%
3	Weighted Average Payroll Tax Rate-PSNH (a)		8.04%
4	Weighted Average Payroll Tax Rate-WMECO (a)		8.04%
5	Incentive Pay Percent (b)		10%
6	Pay Incentive with Tax-NUSCO, CL&P, NSTAR (Ln 5*(1+Ln 2))		10.804%
7	Pay Incentive with Tax-PSNH (Ln 5*(1+Ln 3))		10.804%
8	Pay Incentive with Tax-WMECO (Ln 5*(1+Ln 4))		10.804%

Ln	**CL&P**	**CURRENT YEAR (CY)**	**ANNUALIZED (A)**
9	Salary Savings (c)	$ 27,210	$ 201,607
10	Incentive Pay Savings (Ln 8* Ln 9)	$ 2,940	$ 21,782
11	Merger Reduction Benefits Savings (c)	$ 10,281	$ 76,615
12	**Total Employee Savings(Sum Ln 9+ Ln 10+ Ln 11)**	**$ 40,432**	**$ 300,004**

Ln	**NSTAR**	**CURRENT YEAR (CY)**	**ANNUALIZED (A)**
13	Salary Savings (d)	$ 145,989	$ 249,000
14	Incentive Pay Savings (Ln 8* Ln 13)	$ 15,773	$ 26,902
15	Merger Reduction Benefits Savings (d)	$ 56,211	$ 91,058
16	**Total Employee Savings (Sum Ln 13+ Ln 14+ Ln 15)**	**$ 217,973**	**$ 366,960**

Ln	**PSNH**	**CURRENT YEAR (CY)**	**ANNUALIZED (A)**
17	Salary Savings (e)	$ 27,051	$ 333,289
18	Incentive Pay Savings (Ln 8 * Ln 17)	$ 2,923	$ 36,009
19	Merger Reduction Benefits Savings (e)	$ 13,356	$ 135,447
20	**Total Employee Savings (Sum Ln 17+ Ln 18 + Ln 19)**	**$ 43,330**	**$ 504,745**

Ln	**WMECO**	**CURRENT YEAR (CY)**	**ANNUALIZED (A)**
21	Salary Savings (f)	$ 30,321	$ 189,283
22	Incentive Pay Savings (Ln 8 * Ln 21)	$ 3,276	$ 20,450
23	Merger Reduction Benefits Savings (f)	$ 11,805	$ 71,746
24	**Total Employee Savings (Sum Ln 21+Ln 22+ Ln 23)**	**$ 45,402**	**$ 281,479**

2013

Ln	(D)	(E)	(F)
1	**Benefits/Taxes/Pension Costs:**		
2	Weighted Average Payroll Tax Rate-NUSCO, CL&P, NSTAR (a)		7.40%
3	Weighted Average Payroll Tax Rate-PSNH (a)		7.40%
4	Weighted Average Payroll Tax Rate-WMECO (a)		7.40%
5	Incentive Pay Percent (b)		10%
6	Pay Incentive with Tax-NUSCO, CL&P, NSTAR (Ln 5*(1+Ln 2))		10.740%
7	Pay Incentive with Tax-PSNH (Ln 5*(1+Ln 3))		10.740%
8	Pay Incentive with Tax-WMECO (Ln 5*(1+Ln 4))		10.740%

Ln	**NSTAR**	**CURRENT YEAR (CY)**	**ANNUALIZED (A)**
13	Salary Savings (g)	$ 64,398	$ 131,315
14	Incentive Pay Savings (Ln 8* Ln 13)	$ 6,916	$ 14,103
15	Merger Reduction Benefits Savings (g)	$ 26,705	$ 53,140
16	**Total Employee Savings (Sum Ln 13+ Ln 14+ Ln 15)**	**$ 98,020**	**$ 198,558**

2014

Ln	(G)	(H)	(I)
1	**Benefits/Taxes/Pension Costs:**		
2	Weighted Average Payroll Tax Rate-NUSCO, CL&P, NSTAR (a)		8.05%
3	Weighted Average Payroll Tax Rate-PSNH (a)		7.02%
4	Weighted Average Payroll Tax Rate-WMECO (a)		7.35%
5	Incentive Pay Percent (b)		10%
6	Pay Incentive with Tax-NUSCO, CL&P, NSTAR (Ln 5*(1+Ln 2))		10.805%
7	Pay Incentive with Tax-PSNH (Ln 5*(1+Ln 3))		10.702%
8	Pay Incentive with Tax-WMECO (Ln 5*(1+Ln 4))		10.735%

Ln	**PSNH**	**CURRENT YEAR (CY)**	**ANNUALIZED (A)**
17	Salary Savings (h)	$ 23,632	$ 141,403
18	Incentive Pay Savings (Ln 8 * Ln 17)	$ 2,529	$ 15,133
19	Merger Reduction Benefits Savings (h)	$ 8,728	$ 50,718
20	**Total Employee Savings (Sum Ln 17+ Ln 18 + Ln 19)**	**$ 34,888**	**$ 207,254**

Ln	**WMECO**	**CURRENT YEAR (CY)**	**ANNUALIZED (A)**
21	Salary Savings (i)	$ 49,411	$ 145,444
22	Incentive Pay Savings (Ln 8 * Ln 21)	$ 5,304	$ 15,613
23	Merger Reduction Benefits Savings (i)	$ 16,314	$ 46,263
24	**Total Employee Savings (Sum Ln 21+Ln 22+ Ln 23)**	**$ 71,029**	**$ 207,320**

(a) Weighted Average Payroll Tax Rate was calculated as the ratio of employee payroll taxes to total labor costs in the given year based on queries of Eversource accounting database.
(b) Incentive Pay Percent is based on an average target incentive pay in the given year.
(c) Exhibit No. ES-105, Page 14(CY), Page 18(A), Line 184. CY Salary Savings are in Column F, and CY Benefit Savings Are Column H+K+L. Annualized Salary Savings are in Column N, and Annualized Benefit Savings are Column P + R + S.
(d) Exhibit No. ES-105, Page 14(CY), Page 18(A), Line 185
(e) Exhibit No. ES-105, Page 14(CY), Page 18(A) Line 186
(f) Exhibit No. ES-105, Page 14(CY), Page 18(A), Line 187
(g) Exhibit No. ES-105, Page 21(CY), Page 22(A) Line 45
(h) Exhibit No. ES-105, Page 28(CY), Page 29(A), Line 25
(i) Exhibit No. ES-105, Page 28(CY), Page 29(A), Line 26

PUBLIC VERSION
PROTECTED MATERIALS REDACTED

Eversource Energy Service Company
Corporate & Administrative Labor Savings Exhibit
April 1, 2012 to December 31, 2012 Merger Reductions

Line	Job Title	1/1/14 Comp Col. A	Head Count Col. B	Salary Col. C	Year End Date Col. D	Days in year after Term Date Col. E	2012 Current Year Labor Savings 2012 Salary Savings Col. F	Benefits Loader Col. G	Benefits Savings Col. H	Payroll Tax Loader Col. I	Payroll Tax Savings Col. J	Remove excess FICA in PR Tax Savings	Adjusted PR Tax Savings Col. K	Pension & PBOP Service Cost/Emp	Pension & PBOP Savings Col. L	Total Savings M = F+H+K+L
1	Director, Labor Relations	[redacted]	1	$ [redacted]												
2	Sr Vice President, StrLaw&Pol	[redacted]	1	$ [redacted]												
3	Vice President, Cntrller & CAO	[redacted]	1	$ [redacted]												
4	Director, Load Fore & Analysis	[redacted]	1	$ [redacted]												
5	Vice President, FinStrPlng&Pol	[redacted]	1	$ [redacted]												
6	DIRECTOR-FINANCIAL PLANNING AND ANALYSIS	[redacted]	1	$ [redacted]												
7	Vice President,ElecSysOp&TrDev	[redacted]	1	$ [redacted]												
8	VICE PRESIDENT-SHARED SERVICES	[redacted]	1	$ [redacted]												
9	DIRECTOR-CUSTOMER EXPERIENCE SUPPORT	[redacted]	1	$ [redacted]												
10	DIRECTOR-IT STRATEGY & TECHNICAL SERVICES	[redacted]	1	$ [redacted]												
11	VP-HUMAN RESOURCES	[redacted]	1	$ [redacted]												
12	VICE PRESIDENT-UTILITY SERVICES	[redacted]	1	$ [redacted]												
13	Asst Treasurer, Asset Mgmt	[redacted]	1	$ [redacted]												
14	Director, Facilities Managemnt	[redacted]	1	$ [redacted]												
15	Director, Enterp Strat&Bus Dev	[redacted]	1	$ [redacted]												
16	Director, Enter Infor Srvcs	[redacted]	1	$ [redacted]												
17	Director, Internal Audit	[redacted]	1	$ [redacted]												
18	Director, Tech Srvc Del & Mgmt	[redacted]	1	$ [redacted]												
19	ASSISTANT GENERAL COUNSEL	[redacted]	1	$ [redacted]												
20	Manager, Security & Risk Mgmt	[redacted]	1	$ [redacted]												
21	Supervisor, Facilities Mgmt	[redacted]	1	$ [redacted]												
22	HR CONSULTANT	[redacted]	1	$ [redacted]												
23	OCCUPATIONAL HEALTH NURSE	[redacted]	1	$ [redacted]												
24	HR CONSULTANT	[redacted]	1	$ [redacted]												
25	HEALTH UNIT ASSISTANT C	[redacted]	1	$ [redacted]												
26	WORKERS COMPENSATION ASSISTANT A	[redacted]	1	$ [redacted]												
27	SENIOR HR CONSULTANT	[redacted]	1	$ [redacted]												
28	WORKER'S COMPENSATION ANALYST	[redacted]	1	$ [redacted]												
29	Sr Contract Agent	[redacted]	1	$ [redacted]												
30	Executive Secretary	[redacted]	1	$ [redacted]												
31	Manager, Facilities Services	[redacted]	1	$ [redacted]												
32	Sr Purchasing Agent	[redacted]	1	$ [redacted]												
33	Sr Energy Supply Analyst	[redacted]	1	$ [redacted]												
34	Sr Contract Agent	[redacted]	1	$ [redacted]												
35	BUYER	[redacted]	1	$ [redacted]												
36	ASSOCIATE ENGINEER	[redacted]	1	$ [redacted]												
37	ASSOCIATE REGULATORY PLANNING ANALYST	[redacted]	1	$ [redacted]												
38	SUPERVISOR-CUSTOMER SERVICE	[redacted]	1	$ [redacted]												
39	Supervisor, Call Center	[redacted]	1	$ [redacted]												
40	ADMINISTRATIVE ASSISTANT	[redacted]	1	$ [redacted]												
41	HR CONSULTANT	[redacted]	1	$ [redacted]												
42	IT BUSINESS ANALYST - LEVEL 4	[redacted]	1	$ [redacted]												
43	HR REPRESENTATIVE	[redacted]	1	$ [redacted]												
44	ADMINISTRATIVE ASSISTANT B	[redacted]	1	$ [redacted]												
45	ENGINEERING TECHNICIAN A	[redacted]	1	$ [redacted]												
46	SENIOR HR REPRESENTATIVE	[redacted]	1	$ [redacted]												
47	SOURCING CONSULTANT	[redacted]	1	$ [redacted]												
48	VICE PRESIDENT-COMMUNICATIONS	[redacted]	1	$ [redacted]												
49	CHIEF REPRODUCTION EQUIPMENT OPERATOR	[redacted]	1	$ [redacted]												

PUBLIC VERSION
PROTECTED MATERIALS REDACTED

Eversource Energy Service Company
Corporate & Administrative Labor Savings Exhibit
April 1, 2012 to December 31, 2012 Merger Reductions

							2012 Current Year Labor Savings									
Line	Job Title	1/1/14 Comp Col. A	Head Count Col. B	Salary Col. C	Year End Date Col. D	Days in year after Term Date Col. E	2012 Salary Savings Col. F	Benefits Loader Col. G	Benefits Savings Col. H	Payroll Tax Loader Col. I	Payroll Tax Savings Col. J	Remove excess FICA in PR Tax Savings	Adjusted PR Tax Savings Col. K	Pension & PBOP Service Cost/Emp	Pension & PBOP Savings Col. L	Total Savings M = F+H+K+L
50	ANALYST-GENERAL SERVICES	[redacted]	1	$ [redacted]												
51	ASSOCIATE GAS TRANSPORTATION ANALYST	[redacted]	1	$ [redacted]												
52	ENGINEERING TECHNICIAN A	[redacted]	1	$ [redacted]												
53	REGIONAL SUPERVISOR-FACILITIES	[redacted]	1	$ [redacted]												
54	SUPERVISOR-CUSTOMER SERVICE	[redacted]	1	$ [redacted]												
55	SUPERVISOR-MATERIALS MANAGEMENT	[redacted]	1	$ [redacted]												
56	MANAGER-CUSTOMER SERVICE TRAINING	[redacted]	1	$ [redacted]												
57	PROJECT MANAGER-ENTERPRISE PLANNING	[redacted]	1	$ [redacted]												
58	SUPERVISOR-CUSTOMER SERVICE	[redacted]	1	$ [redacted]												
59	SUPERVISOR-CUSTOMER SERVICE	[redacted]	1	$ [redacted]												
60	Claims Specialist	[redacted]	1	$ [redacted]												
61	Sr Budget & Fore Analyst	[redacted]	1	$ [redacted]												
62	Sr Financial Reporting Analyst	[redacted]	1	$ [redacted]												
63	Manager, Audit	[redacted]	1	$ [redacted]												
64	Executive Secretary	[redacted]	1	$ [redacted]												
65	MANAGER-ACCOUNTING POLICIES AND INTERNAL CONTROLS	[redacted]	1	$ [redacted]												
66	FINANCIAL ANALYST	[redacted]	1	$ [redacted]												
67	COMMUNICATIONS SPECIALIST	[redacted]	1	$ [redacted]												
68	ACCOUNTANT B	[redacted]	1	$ [redacted]												
69	ACCOUNTANT A	[redacted]	1	$ [redacted]												
70	ASSOCIATE REGULATORY PLANNING ANALYST	[redacted]	1	$ [redacted]												
71	MANAGER-TREASURY OPERATIONS	[redacted]	1	$ [redacted]												
72	SENIOR FINANCIAL ANALYST	[redacted]	1	$ [redacted]												
73	COMMUNICATIONS SPECIALIST	[redacted]	1	$ [redacted]												
74	SENIOR REGULATORY INFORMATION PROCESSOR	[redacted]	1	$ [redacted]												
75	ECONOMIC DEVPMNT & COMMUNITY RELATIONS COORDINATOR	[redacted]	1	$ [redacted]												
76	ADMINISTRATIVE ASSISTANT A	[redacted]	1	$ [redacted]												
77	ECONOMIC DEVPMNT & COMMUNITY RELATIONS COORDINATOR	[redacted]	1	$ [redacted]												
78	MANAGER-BUSINESS SERVICES GROUP (CL&P)	[redacted]	1	$ [redacted]												
79	ASSOCIATE ANALYST TRANSMISSION	[redacted]	1	$ [redacted]												
80	CONTRIBUTIONS PROCESSOR-COMMUNITY RELATIONS	[redacted]	1	$ [redacted]												
81	Sr Finan Analyst, Invest Plng	[redacted]	1	$ [redacted]												
82	PROJECT MANAGER	[redacted]	1	$ [redacted]												
83	ASSOCIATE BUSINESS GROUP ANALYST	[redacted]	1	$ [redacted]												
84	DIRECTOR-WMECO COMMUNICATIONS	[redacted]	1	$ [redacted]												
85	LIABILITY CLAIMS MANAGER-LEVEL 3	[redacted]	1	$ [redacted]												
86	MANAGER-REGULATORY POLICY	[redacted]	1	$ [redacted]												
87	PRICING SUPPORT SPECIALIST	[redacted]	1	$ [redacted]												
88	ADMINISTRATIVE ASSISTANT A	[redacted]	1	$ [redacted]												
89	ADMINISTRATIVE ASSISTANT	[redacted]	1	$ [redacted]												
90	ACCOUNTANT A	[redacted]	1	$ [redacted]												
91	SENIOR ECONOMIC AND LOAD ANALYST	[redacted]	1	$ [redacted]												
92	MANAGER-BUSINESS SERVICES GROUP	[redacted]	1	$ [redacted]												
93	FINANCIAL ANALYST	[redacted]	1	$ [redacted]												
94	PUBLIC AFFAIRS SPECIALIST	[redacted]	1	$ [redacted]												
95	LIABILITY CLAIMS MANAGER-LEVEL 3	[redacted]	1	$ [redacted]												
96	BUSINESS UNIT RISK CONTROLLER	[redacted]	1	$ [redacted]												

PUBLIC VERSION
PROTECTED MATERIALS REDACTED

Eversource Energy Service Company
Corporate & Administrative Labor Savings Exhibit
April 1, 2012 to December 31, 2012 Merger Reductions

							2012 Current Year Labor Savings									
Line	Job Title	1/1/14 Comp Col. A	Head Count Col. B	Salary Col. C	Year End Date Col. D	Days in year after Term Date Col. E	2012 Salary Savings Col. F	Benefits Loader Col. G	Benefits Savings Col. H	Payroll Tax Loader Col. I	Payroll Tax Savings Col. J	Remove excess FICA in PR Tax Savings	Adjusted PR Tax Savings Col. K	Pension & PBOP Service Cost/Emp	Pension & PBOP Savings Col. L	Total Savings M = F+H+K+L
97	CORPORATE INSURANCE MANAGER	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
98	TEAM LEADER	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
99	MANAGER-CL&P COMMUNICATIONS	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
100	SENIOR REVENUE REQUIREMENTS ANALYST	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
101	SENIOR CONTRACT SPECIALIST	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
102	ACCOUNTING CLERK A (SUNDRY BILLING)	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
103	REVENUE REQUIREMENTS ANALYST	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
104	MANAGER-UTILITY GROUP ASSET STRATEGY	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
105	ADMINISTRATIVE ASSISTANT	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
106	PROJECT MANAGER-SYSTEM RECRUITMENT	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
107	MGR-CUST BLNG SVCS & LRG PWR BILLING (IO)	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
108	MANAGER-ECONOMIC DEVELOPMENT & COMMUNITY RELATIONS	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
109	BUSINESS DEVELOPMENT CONSULTANT	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
110	PROCESS ANALYST-CL&P SYSTEM	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
111	MGR-TRNS PERFRMCE ANALYS & REPORTING & DOC CNTRL	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
112	Business Systems Analyst	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
113	Project Manager, Bus Sys Mgmt	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
114	ENVIRONMENTAL COORDINATOR	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
115	ENVIRONMENTAL TECHNICIAN A	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
116	IT CLIENT SERVICES REPRESENTATIVE - LEVEL 3	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
117	IT INFORMATION MODELER - LEVEL 4	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
118	LEGAL ADMINISTRATIVE ASSISTANT	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
119	SENIOR COUNSEL	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
120	LEGAL ADMINISTRATIVE ASSISTANT	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
121	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
122	ENVIRONMENTAL COORDINATOR	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
123	ENVIRONMENTAL TECHNICIAN A	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
124	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
125	ACCOUNTANT A	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
126	TECHNICAL ASSOCIATE	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
127	IT SYSTEMS ENGINEER - LEVEL 3	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
128	ENVIRONMENTAL COORDINATOR	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
129	CLERK	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
130	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 2	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
131	IT CLIENT SERVICES REPRESENTATIVE - LEVEL 3	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
132	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
133	TECHNICAL ASSOCIATE	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
134	IT ADMINISTRATIVE REPRESENTATIVE A	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
135	ADMINISTRATIVE ASSISTANT	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
136	ENERGY SERVICES REPRESENTATIVE	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
137	WORKFORCE SCHEDULING ASSOCIATE	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
138	ASSOCIATE CUSTOMER SERVICES TRAINING COORDINATOR	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
139	CUSTOMER SERVICES TRAINING COORDINATOR	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
140	TEAM LEADER-CUSTOMER EXPERIENCE	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
141	CUSTOMER SERVICES TRAINING COORDINATOR	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
142	REVENUE PROTECTION RECOVERY SPECIALIST	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
143	ENERGY SERVICES REPRESENTATIVE	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
144	QUALITY ASSURANCE ADVISOR	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Eversource Energy Service Company
Corporate & Administrative Labor Savings Exhibit
April 1, 2012 to December 31, 2012 Merger Reductions

Line	Job Title	1/1/14 Comp Col. A	Head Count Col. B	Salary Col. C	Year End Date Col. D	Days in year after Term Date Col. E	2012 Current Year Labor Savings: 2012 Salary Savings Col. F	Benefits Loader Col. G	Benefits Savings Col. H	Payroll Tax Loader Col. I	Payroll Tax Savings Col. J	Remove excess FICA in PR Tax Savings	Adjusted PR Tax Savings Col. K	Pension & PBOP Service Cost/Emp	Pension & PBOP Savings Col. L	Total Savings M = F+H+K+L
145	ENERGY SERVICES REPRESENTATIVE	[redacted]	1	$ [redacted]												
146	TEAM LEADER-CUSTOMER EXPERIENCE		1	$												
147	PROJECT MANAGER-PILOT CUSTOMER EXPERIENCE (IO)		1	$												
148	ENERGY SERVICES REPRESENTATIVE		1	$												
149	REVENUE INVESTIGATOR		1	$												
150	CUSTOMER SERVICES TRAINING COORDINATOR		1	$												
151	ASSOCIATE CUSTOMER SERVICES TRAINING COORDINATOR		1	$												
152	MANAGER-UG REVENUE STREAM OPERATIONS		1	$												
153	SENIOR ACCOUNT EXECUTIVE-CL&P		1	$												
154	SENIOR ANALYST		1	$												
155	CUSTOMER SERVICES TRAINING COORDINATOR		1	$												
156	ENERGY SERVICES REPRESENTATIVE		1	$												
157	SUPERVISOR CALL CENTER		1	$												
158	CUSTOMER SERVICES TRAINING COORDINATOR		1	$												
159	ADMINISTRATIVE ASSISTANT		1	$												
160	CUSTOMER SERVICE CONSULTANT		1	$												
161	REVENUE INVESTIGATOR		1	$												
162	Revenue Assurance Specialist		1	$												
163	Revenue Assurance Specialist		1	$												
164	TECHNICAL ASSOCIATE-CUSTOMER SERVICE CONSULTANT		1	$												
165	Tax Research Principal		1	$												
166	LEGAL ADMINISTRATIVE ASSISTANT		1	$												
167	ENVIRONMENTAL RECORDS TECHNICIAN A		1	$												
168	IT SUPPORT CENTER CONSULTANT - LEVEL 3		1	$												
169	ASSOCIATE CUSTOMER SERVICES TRAINING COORDINATOR		1	$												
170	Manager, Corporate Security		1	$												
171	SUPERVISOR-ENGINEERING & DESIGN		1	$												
172	ACCOUNT EXECUTIVE		1	$												
173	CUSTOMER SERVICE CONSULTANT		1	$												
174	SUPERVISOR-CUSTOMER EXPERIENCE BUDGETS AND GOALS		1	$												
175	BUSINESS INTEGRATION MANAGER		1	$												
176	SENIOR ACCOUNT EXECUTIVE-CL&P		1	$												
177	SUPERVISOR-ACCOUNT EXECUTIVES		1	$												
178	REGIONAL CONSERVATION & LOAD MANAGEMENT MANAGER		1	$												
179	MANAGER-CORPORATE FINANCIAL FORECASTING		1	$												
180	HR CONSULTANT		1	$												
181	VICE PRESIDENT GENERATION-PSNH		1	$												
182			**181**	**$ 17,599,967**			**$ 5,714,838**		**$ 1,222,431**		**$ 471,961**	**$ (29,212)**	**$ 442,749**		**$ 714,187**	**$ 8,094,205**
		Totals By Company														
183		[redacted]	173	$ [redacted]			$ [redacted]		$ [redacted]		$ [redacted]				$ [redacted]	
184			2	$			$		$		$				$	
185			1	$			$		$		$				$	
186			3	$			$		$		$				$	
187			2	$			$		$		$				$	
188		Total	181	$ 17,599,971			$ 5,714,837		$ 1,222,431		$ 471,961	$ (29,212)	$ 442,749		$ 714,187	$ 8,094,204

Eversource Energy Service Company
Corporate & Administrative Labor Savings Exhibit
April 1, 2012 to December 31, 2012 Merger Reductions

Line	Job Title	1/1/14 Company Col. A	Head Count Col. B	Salary Col. C	Year End Date Col. D	Days in year after Term Date Col. E	2012 Salary Savings Col. N	Benefit Loader Col. O	Benefit Savings Col. P	Payroll Tax Loader Col. Q	Payroll Tax Savings	Remove excess FICA in PR Tax Savings	Adjusted PR Tax Savings Col. R	Pension & PBOP Savings Col. S	Total Savings T= N + P + R + S
							2012 Annualized Labor Savings								
1	Director, Labor Relations	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	Sr Vice President, StrLaw&Pol	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	Vice President, Cntrller & CAO	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	Director, Load Fore & Analysis	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5	Vice President, FinStrPlng&Pol	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6	DIRECTOR-FINANCIAL PLANNING AND ANALYSIS	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7	Vice President,ElecSysOp&TrDev	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8	VICE PRESIDENT-SHARED SERVICES	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9	DIRECTOR-CUSTOMER EXPERIENCE SUPPORT	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10	DIRECTOR-IT STRATEGY & TECHNICAL SERVICES	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
11	VP-HUMAN RESOURCES	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
12	VICE PRESIDENT-UTILITY SERVICES	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
13	Asst Treasurer, Asset Mgmt	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
14	Director, Facilities Managemnt	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
15	Director, Enterp Strat&Bus Dev	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
16	Director, Enter Infor Srvcs	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
17	Director, Internal Audit	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
18	Director, Tech Srvc Del & Mgmt	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
19	ASSISTANT GENERAL COUNSEL	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
20	Manager, Security & Risk Mgmt	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
21	Supervisor, Facilities Mgmt	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
22	HR CONSULTANT	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
23	OCCUPATIONAL HEALTH NURSE	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
24	HR CONSULTANT	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
25	HEALTH UNIT ASSISTANT C	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
26	WORKERS COMPENSATION ASSISTANT A	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
27	SENIOR HR CONSULTANT	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
28	WORKER'S COMPENSATION ANALYST	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
29	Sr Contract Agent	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
30	Executive Secretary	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
31	Manager, Facilities Services	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
32	Sr Purchasing Agent	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
33	Sr Energy Supply Analyst	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
34	Sr Contract Agent	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
35	BUYER	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
36	ASSOCIATE ENGINEER	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
37	ASSOCIATE REGULATORY PLANNING ANALYST	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
38	SUPERVISOR-CUSTOMER SERVICE	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
39	Supervisor, Call Center	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
40	ADMINISTRATIVE ASSISTANT	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
41	HR CONSULTANT	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
42	IT BUSINESS ANALYST - LEVEL 4	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
43	HR REPRESENTATIVE	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
44	ADMINISTRATIVE ASSISTANT B	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
45	ENGINEERING TECHNICIAN A	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
46	SENIOR HR REPRESENTATIVE	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
47	SOURCING CONSULTANT	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
48	VICE PRESIDENT-COMMUNICATIONS	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
49	CHIEF REPRODUCTION EQUIPMENT OPERATOR	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

PUBLIC VERSION
PROTECTED MATERIALS REDACTED

Eversource Energy Service Company
Corporate & Administrative Labor Savings Exhibit
April 1, 2012 to December 31, 2012 Merger Reductions

Line	Job Title	1/1/14 Company Col. A	Head Count Col. B	Salary Col. C	Year End Date Col. D	Days in year after Term Date Col. E	2012 Annualized Labor Savings: 2012 Salary Savings Col. N	Benefit Loader Col. O	Benefit Savings Col. P	Payroll Tax Loader Col. Q	Payroll Tax Savings	Remove excess FICA in PR Tax Savings	Adjusted PR Tax Savings Col. R	Pension & PBOP Savings Col. S	Total Savings T= N + P + R + S
50	ANALYST-GENERAL SERVICES	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
51	ASSOCIATE GAS TRANSPORTATION ANALYST	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
52	ENGINEERING TECHNICIAN A	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
53	REGIONAL SUPERVISOR-FACILITIES	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
54	SUPERVISOR-CUSTOMER SERVICE	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
55	SUPERVISOR-MATERIALS MANAGEMENT	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
56	MANAGER-CUSTOMER SERVICE TRAINING	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
57	PROJECT MANAGER-ENTERPRISE PLANNING	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
58	SUPERVISOR-CUSTOMER SERVICE	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
59	SUPERVISOR-CUSTOMER SERVICE	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
60	Claims Specialist	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
61	Sr Budget & Fore Analyst	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
62	Sr Financial Reporting Analyst	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
63	Manager, Audit	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
64	Executive Secretary	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
65	MANAGER-ACCOUNTING POLICIES AND INTERNAL CONTROLS	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
66	FINANCIAL ANALYST	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
67	COMMUNICATIONS SPECIALIST	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
68	ACCOUNTANT B	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
69	ACCOUNTANT A	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
70	ASSOCIATE REGULATORY PLANNING ANALYST	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
71	MANAGER-TREASURY OPERATIONS	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
72	SENIOR FINANCIAL ANALYST	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
73	COMMUNICATIONS SPECIALIST	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
74	SENIOR REGULATORY INFORMATION PROCESSOR	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
75	ECONOMIC DEVPMNT & COMMUNITY RELATIONS COORDINATOR	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
76	ADMINISTRATIVE ASSISTANT A	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
77	ECONOMIC DEVPMNT & COMMUNITY RELATIONS COORDINATOR	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
78	MANAGER-BUSINESS SERVICES GROUP (CL&P)	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
79	ASSOCIATE ANALYST TRANSMISSION	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
80	CONTRIBUTIONS PROCESSOR-COMMUNITY RELATIONS	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
81	Sr Finan Analyst, Invest Plng	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
82	PROJECT MANAGER	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
83	ASSOCIATE BUSINESS GROUP ANALYST	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
84	DIRECTOR-WMECO COMMUNICATIONS	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
85	LIABILITY CLAIMS MANAGER-LEVEL 3	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
86	MANAGER-REGULATORY POLICY	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
87	PRICING SUPPORT SPECIALIST	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
88	ADMINISTRATIVE ASSISTANT A	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
89	ADMINISTRATIVE ASSISTANT	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
90	ACCOUNTANT A	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
91	SENIOR ECONOMIC AND LOAD ANALYST	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
92	MANAGER-BUSINESS SERVICES GROUP	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
93	FINANCIAL ANALYST	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
94	PUBLIC AFFAIRS SPECIALIST	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
95	LIABILITY CLAIMS MANAGER-LEVEL 3	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Eversource Energy Service Company
Corporate & Administrative Labor Savings Exhibit
April 1, 2012 to December 31, 2012 Merger Reductions

							2012 Annualized Labor Savings								
Line	Job Title	1/1/14 Company Col. A	Head Count Col. B	Salary Col. C	Year End Date Col. D	Days in year after Term Date Col. E	2012 Salary Savings Col. N	Benefit Loader Col. O	Benefit Savings Col. P	Payroll Tax Loader Col. Q	Payroll Tax Savings	Remove excess FICA in PR Tax Savings	Adjusted PR Tax Savings Col. R	Pension & PBOP Savings Col. S	Total Savings T= N + P + R + S
96	BUSINESS UNIT RISK CONTROLLER	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
97	CORPORATE INSURANCE MANAGER	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
98	TEAM LEADER	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
99	MANAGER-CL&P COMMUNICATIONS	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
100	SENIOR REVENUE REQUIREMENTS ANALYST	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
101	SENIOR CONTRACT SPECIALIST	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
102	ACCOUNTING CLERK A (SUNDRY BILLING)	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
103	REVENUE REQUIREMENTS ANALYST	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
104	MANAGER-UTILITY GROUP ASSET STRATEGY	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
105	ADMINISTRATIVE ASSISTANT	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
106	PROJECT MANAGER-SYSTEM RECRUITMENT	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
107	MGR-CUST BLNG SVCS & LRG PWR BILLING (IO)	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
108	MANAGER-ECONOMIC DEVELOPMENT & COMMUNITY RELATIONS	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
109	BUSINESS DEVELOPMENT CONSULTANT	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
110	PROCESS ANALYST-CL&P SYSTEM	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
111	MGR-TRNS PERFRMCE ANALYS & REPORTING & DOC CNTRL	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
112	Business Systems Analyst	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
113	Project Manager, Bus Sys Mgmt	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
114	ENVIRONMENTAL COORDINATOR	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
115	ENVIRONMENTAL TECHNICIAN A	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
116	IT CLIENT SERVICES REPRESENTATIVE - LEVEL 3	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
117	IT INFORMATION MODELER - LEVEL 4	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
118	LEGAL ADMINISTRATIVE ASSISTANT	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
119	SENIOR COUNSEL	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
120	LEGAL ADMINISTRATIVE ASSISTANT	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
121	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
122	ENVIRONMENTAL COORDINATOR	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
123	ENVIRONMENTAL TECHNICIAN A	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
124	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
125	ACCOUNTANT A	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
126	TECHNICAL ASSOCIATE	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
127	IT SYSTEMS ENGINEER - LEVEL 3	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
128	ENVIRONMENTAL COORDINATOR	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
129	CLERK	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
130	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 2	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
131	IT CLIENT SERVICES REPRESENTATIVE - LEVEL 3	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
132	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
133	TECHNICAL ASSOCIATE	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
134	IT ADMINISTRATIVE REPRESENTATIVE A	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
135	ADMINISTRATIVE ASSISTANT	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
136	ENERGY SERVICES REPRESENTATIVE	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
137	WORKFORCE SCHEDULING ASSOCIATE	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
138	ASSOCIATE CUSTOMER SERVICES TRAINING COORDINATOR	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

PUBLIC VERSION
PROTECTED MATERIALS REDACTED

Eversource Energy Service Company
Corporate & Administrative Labor Savings Exhibit
April 1, 2012 to December 31, 2012 Merger Reductions

Line	Job Title	1/1/14 Company Col. A	Head Count Col. B	Salary Col. C	Year End Date Col. D	Days in year after Term Date Col. E	2012 Annualized Labor Savings: 2012 Salary Savings Col. N	Benefit Loader Col. O	Benefit Savings Col. P	Payroll Tax Loader Col. Q	Payroll Tax Savings	Remove excess FICA in PR Tax Savings	Adjusted PR Tax Savings Col. R	Pension & PBOP Savings Col. S	Total Savings T= N + P + R + S
139	CUSTOMER SERVICES TRAINING COORDINATOR	[redacted]	1	$ [redacted]											
140	TEAM LEADER-CUSTOMER EXPERIENCE		1	$											
141	CUSTOMER SERVICES TRAINING COORDINATOR		1	$											
142	REVENUE PROTECTION RECOVERY SPECIALIST		1	$											
143	ENERGY SERVICES REPRESENTATIVE		1	$											
144	QUALITY ASSURANCE ADVISOR		1	$											
145	ENERGY SERVICES REPRESENTATIVE		1	$											
146	TEAM LEADER-CUSTOMER EXPERIENCE		1	$											
147	PROJECT MANAGER-PILOT CUSTOMER EXPERIENCE (IO)		1	$											
148	ENERGY SERVICES REPRESENTATIVE		1	$											
149	REVENUE INVESTIGATOR		1	$											
150	CUSTOMER SERVICES TRAINING COORDINATOR		1	$											
151	ASSOCIATE CUSTOMER SERVICES TRAINING COORDINATOR		1	$											
152	MANAGER-UG REVENUE STREAM OPERATIONS		1	$											
153	SENIOR ACCOUNT EXECUTIVE-CL&P		1	$											
154	SENIOR ANALYST		1	$											
155	CUSTOMER SERVICES TRAINING COORDINATOR		1	$											
156	ENERGY SERVICES REPRESENTATIVE		1	$											
157	SUPERVISOR CALL CENTER		1	$											
158	CUSTOMER SERVICES TRAINING COORDINATOR		1	$											
159	ADMINISTRATIVE ASSISTANT		1	$											
160	CUSTOMER SERVICE CONSULTANT		1	$											
161	REVENUE INVESTIGATOR		1	$											
162	Revenue Assurance Specialist		1	$											
163	Revenue Assurance Specialist		1	$											
164	TECHNICAL ASSOCIATE-CUSTOMER SERVICE CONSULTANT		1	$											
165	Tax Research Principal		1	$											
166	LEGAL ADMINISTRATIVE ASSISTANT		1	$											
167	ENVIRONMENTAL RECORDS TECHNICIAN A		1	$											
168	IT SUPPORT CENTER CONSULTANT - LEVEL 3		1	$											
169	ASSOCIATE CUSTOMER SERVICES TRAINING COORDINATOR		1	$											
170	Manager, Corporate Security		1	$											
171	SUPERVISOR-ENGINEERING & DESIGN		1	$											
172	ACCOUNT EXECUTIVE		1	$											
173	CUSTOMER SERVICE CONSULTANT		1	$											
174	SUPERVISOR-CUSTOMER EXPERIENCE BUDGETS AND GOALS		1	$											
175	BUSINESS INTEGRATION MANAGER		1	$											
176	SENIOR ACCOUNT EXECUTIVE-CL&P		1	$											
177	SUPERVISOR-ACCOUNT EXECUTIVES		1	$											
178	REGIONAL CONSERVATION & LOAD MANAGEMENT MANAGER		1	$											
179	MANAGER-CORPORATE FINANCIAL FORECASTING		1	$											
180	HR CONSULTANT		1	$											
181	VICE PRESIDENT GENERATION-PSNH		1	$											
182			181	$ 17,599,967			$ 17,599,971		$ 3,635,282		$ 1,433,855	$ (171,742)	$ 1,262,114	$ 2,513,861	$ 25,011,227
		Totals By Company													
183		[redacted]	173	$ [redacted]			$ [redacted]		$ [redacted]		$ [redacted]				
184			2	$			$		$		$				
185			1	$			$		$		$				
186			3	$			$		$		$				
187			2	$			$		$		$				
188		Total	181	$ 17,599,971			$ 17,599,971		$ 3,635,282		$ 1,433,855	$ (171,742)	$ 1,262,114	$ 2,513,861	$ 25,011,227

NUSCO Shared Services*
Corporate & Administrative Labor Savings Exhibit
April 1, 2012 to December 31, 2012 Merger Attrition

Line	(A) Job Title	(B) 1/1/14 Company	(C) Employees
1	SUPERVISOR-MAINTENANCE (NGS)	[redacted]	1
2	ANALYST		1
3	IT SUPERVISOR-DESKTOP SERVICES		1
4	MANAGER-PROPERTY TAX		1
5	ASSOCIATE ANALYST		1
6	HYPERION PLANNING SYSTEMS CONSULTANT		1
7	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 4		1
8	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 4		1
9	TEAM LEADER		1
10	IT BUSINESS APPLICATION SYSTEMS DEVELOPER- LEVEL 1		1
11	IT SOFTWARE ENGINEER - LEVEL 4		1
12	SENIOR TAX ACCOUNTANT		1
13	IT COMPUTER SECURITY TECHNICIAN - LEVEL 3		1
14	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3		1
15	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3		1
16	STAFF ACCOUNTANT		1
17	PAINTER		1
18	TEAM LEADER		1
19	ASSOCIATE ENGINEER		1
20	IT SECURITY ENGINEER LEVEL 2		1
21	BUYER		1
22	IT TELECOMMUNICATIONS ENGINEER - LEVEL 4		1
23	TECHNICAL ASSOCIATE		1
24	IT BUSINESS SOLUTIONS ANALYST-LEVEL 3		1
25	ASSOCIATE REVENUE REQUIREMENTS ANALYST		1
26	ASSOCIATE TAX ACCOUNTANT		1
27	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 4		1
28	ASSOCIATE TAX ACCOUNTANT		1
29	HR CONSULTANT		1
30	MANAGER-ORGANIZATIONAL EFFECTIVENESS		1
31	ETHICS, DIVERSITY & EEO PROGRAM MANAGER (RA)		1
32	SENIOR COUNSEL		1
33	SENIOR COUNSEL		1
34	SENIOR COUNSEL		1
35	RATE SERVICES SUPERVISOR		1
36	SUPERVISOR-REGULATORY INFORMATION PROCESSING		1
37	ANALYST		1
38	COUNSEL		1
39	MANAGER-EXECUTIVE COMMUNICATIONS&CREATIVE SERVICES		1
40	PROGRAM ADMINISTRATOR-EVALUATOR C&LM		1
41	CHAIRMAN - PRESIDENT AND CHIEF EXECUTIVE OFFICER		1
42	Office Cleaner-Southern Dstrct		1
43	Util Wrkr Bldg Mai A		1
44	Sr Labor Relations Consultant		1
45	Director, Reg Policy & Rates		1
46	Manager, Financial Reporting		1
47	Bldgs Maint Mechanic/Electricn		1
48	Accounting Analyst		1
49	Mechanic Facilities-Journey		1
50	Trucking Coordinator		1
51	Util Wrkr Bldg Mai A		1
52	Security Analyst		1

*On July 1, 2015, Northeast Utilities Service Company's (NUSCO) legal name was changed to Eversource Energy Service Company.

NUSCO Shared Services*
Corporate & Administrative Labor Savings Exhibit
April 1, 2012 to December 31, 2012 Merger Attrition

Line	(A) Job Title	(B) 1/1/14 Company	(C) Employees
53	Sr Security Analyst	[redacted]	1
54	Stockhandler		1
55	Lead Program Manager, C&I Impl		1
56	Proj Coordinator, Energy Effic		1
57		**Exits 4/1/12 to 12/31/12:**	**-56**

Line	(A) Job Title	(B) 1/1/14 Company	(C) Employees
58	MANAGER-YANKEE GAS COMMUNICATIONS	[redacted]	1
59	IT BUSINESS APPLICATION SYSTEMS DEVELOPER- LEVEL 1		1
60	IT BUSINESS APPLICATION SYSTEMS DEVELOPER- LEVEL 1		1
61	IT COMPUTER SECURITY TECHNICIAN - LEVEL 2		1
62	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3		1
63	IT SECURITY ENGINEER LEVEL 1		1
64	IT TELECOMMUNICATIONS ENGINEER - LEVEL 1		1
65	MANAGER-MEDIA RELATIONS (CT)		1
66	COUNSEL		1
67	SENIOR COMMUNICATIONS SPECIALIST		1
68	SENIOR COMPENSATION ANALYST		1
69	COMPENSATION ANALYST		1
70	TECHNICAL ASSOCIATE		1
71	ANALYST		1
72	TECHNICAL ASSOCIATE		1
73	LICENSING & PERMITTING SPECIALIST (PSNH)		1
74	ENERGY ENGINEER		1
75	PROGRAM ADMINISTRATOR-EVALUATOR		1
76	PROGRAM ADMINISTRATOR-EVALUATOR		1
77	ASSOCIATE PROGRAM ADMINISTRATOR-EVALUATOR C&LM		1
78	ASSOCIATE ENERGY ENGINEER		1
79	ASSOCIATE ENERGY ENGINEER		1
80	PROGRAM ADMINISTRATOR-EVALUATOR		1
81	PROGRAM ADMINISTRATOR-EVALUATOR		1
82	PROGRAM ADMINISTRATOR-EVALUATOR		1
83	ASSOCIATE PROGRAM ADMINISTRATOR-EVALUATOR C&LM		1
84	Benefits Representative		1
85	Computer Technician		1
86	Stockhandler		1
87	Labor Relations Coordinator		1
88	Supervisor, Field Safety		1
89	Senior Contract Agent		1
90	Senior Contract Agent		1
91	Lead HR Business Partner		1
92	Program Manager, Implement		1
93	Sr Research Analyst, Enrgy Con		1
94	Energ Efficiency Proj Engineer		1
95		**Hires 4/1/12 to 12/31/12:**	**37**
96		**Net Attrition:**	**-19**

*On July 1, 2015, Northeast Utilities Service Company's (NUSCO) legal name was changed to Eversource Energy Service Company.

Merger-related attrition is the difference between the number of employee exits and the number of new hires for employees who performed shared services functions on a year-by-year basis.

PUBLIC VERSION
PROTECTED MATERIALS REDACTED

Eversource Energy Service Company
Corporate & Administrative Labor Savings Exhibit
January 1, 2013 to December 31, 2013 Merger Reductions

							2013 Current Year Labor Savings									
Line	Job Title	1/1/14 Company Col. A	Head Count Col. B	Salary Col. C	Year End Date Col. D	Days in year after Term Date Col. E	2013 Salary Savings Col. F	Benefits Loader Col. G	Benefits Savings Col. H	Payroll Tax Loader Col. I	Payroll Tax Savings Col. J	Remove excess FICA in PR Tax Savings	Adjusted PR Tax Savings Col. K	Pension & PBOP Service Cost/Emp	Pension & PBOP Savings Col. L	Total Savings M = F+H+K+L
1	Accounting Clerk A	[redacted]	1	$ [redacted]												
2	Internal Auditor		1	$												
3	Sr. Internal Auditor		1	$												
4	Accounting Clerk A		1	$												
5	Accounting Clerk A		1	$												
6	Accounting Clerk A		1	$												
7	Accounting Clerk A		1	$												
8	Accounting Clerk A		1	$												
9	Transporation Assistant A (SW)		1	$												
10	Administrative Assistant A		1	$												
11	IT Technician-Level 2		1	$												
12	Senior Accounting Clerk		1	$												
13	Chief Accounting Clerk		1	$												
14	Administrative Assistant		1	$												
15	Administrative Assistant		1	$												
16	Sr. Internal Auditor		1	$												
17	IT COMPUTER OPERATORS - LEVEL 3 (SW)		1	$												
18	Executive Assistant		1	$												
19	Executive Assistant		1	$												
20	Human Resources Business Partner		1	$												
21	Health Administrator		1	$												
22	Supervisor, Accounts Payable		1	$												
23	Customer Service Consultant		1	$												
24	Safety and Environmental Coordinator-Transmissions		1	$												
25	Senior Internal Auditor		1	$												
26	Team Leader-Transmission Contracts		1	$												
27	Business Intergration Manager		1	$												
28	Manager, Trans Susta&Dist SC		1	$												
29	Manager, Community Relations		1	$												
30	Manager, Directory & Appl Srvs		1	$												
31	Manager, Power Systems Operations Training		1	$												
32	Director, Municipal Relations and Siting		1	$												
33	Director, Transmission Asset Strategy		1	$												
34	Director-Training		1	$												
35	Director-IT Operations		1	$												
36	Director-Enterprise Planning and Development		1	$												
37	Executive Director-IT		1	$												
38	Vice President Intergration Planning		1	$												
39	Chief Compliance Officer		1	$												
40	VP REGULATORY AFFAIRS (SPECIAL ASSIGNMENT)		1	$												
41	SR VP Corporate Strategy & Environmenta		1	$												
42			**41**	**$ 4,394,621**			**$ 3,002,344**		**$ 614,055**		**$ 240,431**	**$ (37,914)**	**$ 202,518**		**$ 416,545**	**$ 4,235,461**
		Totals By Company														
43		[redacted]	40	$ [redacted]			$ [redacted]		$ [redacted]		$ [redacted]				$ [redacted]	
44			-	$			$		$		$				$	
45			1	$			$		$		$				$	
46			-	$			$		$		$				$	
47			-	$			$		$		$				$	
48		Total	41	$ 4,394,621			$ 3,002,342		$ 614,055		$ 240,431	$ (37,914)	$ 202,517		$ 416,545	$ 4,235,459

Eversource Energy Service Company
Corporate & Administrative Labor Savings Exhibit
January 1, 2013 to December 31, 2013 Merger Reductions

Line	Job Title	1/1/14 Company Col. A	Head Count Col. B	Salary Col. C	Year End Date Col. D	Days in year after Term Date Col. E	2013 Annualized Labor Savings: 2013 Salary Savings Col. N	Benefit Loader Col. O	Benefit Savings Col. P	Payroll Tax Loader Col. Q	Payroll Tax Savings	Remove excess FICA in PR Tax Savings	Adjusted PR Tax Savings Col. R	Pension & PBOP Savings Col. S	Total Savings T= N + P + R + S
1	Accounting Clerk A	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	Internal Auditor	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	Sr. Internal Auditor	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	Accounting Clerk A	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5	Accounting Clerk A	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6	Accounting Clerk A	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7	Accounting Clerk A	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8	Accounting Clerk A	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9	Transporation Assistant A (SW)	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10	Administrative Assistant A	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
11	IT Technician-Level 2	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
12	Senior Accounting Clerk	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
13	Chief Accounting Clerk	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
14	Administrative Assistant	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
15	Administrative Assistant	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
16	Sr. Internal Auditor	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
17	IT COMPUTER OPERATORS - LEVEL 3 (SW)	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
18	Executive Assistant	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
19	Executive Assistant	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
20	Human Resources Business Partner	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
21	Health Administrator	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
22	Supervisor, Accounts Payable	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
23	Customer Service Consultant	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
24	Safety and Environmental Coordinator-Transmissions	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
25	Senior Internal Auditor	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
26	Team Leader-Transmission Contracts	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
27	Business Intergration Manager	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
28	Manager, Trans Susta&Dist SC	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
29	Manager, Community Relations	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
30	Manager, Directory & Appl Srvs	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
31	Manager, Power Systems Operations Training	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
32	Director, Municipal Relations and Siting	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
33	Director, Transmission Asset Strategy	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
34	Director-Training	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
35	Director-IT Operations	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
36	Director-Enterprise Planning and Development	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
37	Executive Director-IT	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
38	Vice President Intergration Planning	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
39	Chief Compliance Officer	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
40	VP REGULATORY AFFAIRS (SPECIAL ASSIGNMENT)	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
41	SR VP Corporate Strategy & Environmental	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
42			**41**	**$ 4,394,621**			**$ 4,394,621**		**$ 901,004**		**$ 352,996**	**$ (74,959)**	**$ 278,037**	**$ 652,078**	**$ 6,225,740**
		Totals By Company													
43		[redacted]	40	$ [redacted]			$ [redacted]		$ [redacted]		$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]
44		[redacted]	-	$ [redacted]			$ [redacted]		$ [redacted]		$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]
45		[redacted]	1	$ [redacted]			$ [redacted]		$ [redacted]		$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]
46		[redacted]	-	$ [redacted]			$ [redacted]		$ [redacted]		$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]
47		[redacted]	-	$ [redacted]			$ [redacted]		$ [redacted]		$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]
48		Total	41	$ 4,394,621			$ 4,394,621		$ 901,004		$ 352,996	$ (74,959)	$ 278,037	$ 652,078	$ 6,225,740

NUSCO Shared Services*
Corporate & Administrative Labor Savings Exhibit
January 1, 2013 to December 31, 2013 Merger Attrition

Line	(A) Job Title	(B) 1/1/14 Company	(C) Employees
1	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3	[redacted]	1
2	SR BUDGET ANALYST		1
3	IT COMPUTER SECURITY TECHNICIAN - LEVEL 2		1
4	MANAGER-REVENUE REGULATION & LOAD RESOURCES		1
5	SENIOR COUNSEL		1
6	IT TECHNICIAN-LEVEL 2		1
7	IT BUSINESS APPLICATION SYSTEMS DEVELOPER- LEVEL 1		1
8	DIRECTOR-REVENUE REQUIREMENTS		1
9	STAFF ACCOUNTANT		1
10	SENIOR STAFF ACCOUNTANT		1
11	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3		1
12	IT NETWORK ANALYST - LAN/WAN - LEVEL 2		1
13	SUPERVISOR, COMPLIANCE & REPORTING		1
14	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3		1
15	INTERNAL AUDITOR		1
16	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 4		1
17	EASEMENT COORDINATOR-DISTRIBUTION (SW)		1
18	IT SYSTEMS ENGINEER - LEVEL 3		1
19	IT BUSINESS SOLUTIONS ANALYST-LEVEL 4		1
20	BUSINESS INTELLIGENCE ANALYST		1
21	TEAM LEADER-CUSTOMER EXPERIENCE		1
22	TEAM LEADER-CUSTOMER EXPERIENCE		1
23	RESEARCH ANALYST		1
24	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 2		1
25	SENIOR METER OPERATIONS SPECIALIST		1
26	BENEFITS FINANCIAL ANALYST		1
27	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 2		1
28	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 2		1
29	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 4		1
30	IT SECURITY ENGINEER LEVEL 3		1
31	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 4		1
32	SENIOR METER OPERATIONS SPECIALIST		1
33	ASSOCIATE CUSTOMER SERVICE CONSULTANT		1
34	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 4		1
35	SENIOR STAFF ACCOUNTANT		1
36	DEPRECIATION ANALYST		1
37	SENIOR TAX ACCOUNTANT		1
38	SENIOR ORGANIZATIONAL DEVELOPMENT CONSULTANT		1
39	IT SECURITY ENGINEER LEVEL 1		1
40	IT SECURITY ENGINEER LEVEL 3		1
41	FINANCIAL ANALYST		1
42	IT SYSTEMS ENGINEER - LEVEL 2		1
43	MANAGER-INCOME TAX		1
44	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 2		1
45	ACCOUNTING SYSTEMS ANALYST I		1
46	MANAGER, REGULATORY POLICY & STRATEGY		1
47	TEAM LEADER		1
48	HR COORDINATOR		1
49	MANAGER, EMPL & CUST COMM		1
50	MEDIA SPECIALIST		1
51	ANALYST		1

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NUSCO Shared Services*

Corporate & Administrative Labor Savings Exhibit

January 1, 2013 to December 31, 2013 Merger Attrition

Line	(A) Job Title	(B) 1/1/14 Company	(C) Employees
52	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 2	[redacted]	1
53	BUILDING MAINT MECHANIC (DUAL LICENSE)		1
54	AREA STOCKHANDLER		1
55	STOCKHANDLER		1
56	MATERIAL PLANNER		1
57	PROJECT MANAGER		1
58	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 4		1
59	IT VOICE COMMUNICATIONS ANALYST - LEVEL 3		1
60	STOCKHANDLER I-NH-RBG		1
61	ANALYST		1
62	MANAGER, REVENUE REQUIREMENTS		1
63	MANAGER, COMMUNITY RELATIONS		1
64	GARAGE MECHANIC		1
65	COMMUNITY RELATIONS SPECIALIST		1
66	MARKETING ANALYST		1
67	TECHNICAL TRAINING SUPERVISOR-OPERS		1
68	ASSOCIATE INSIDE SALES CONSULTANT		1
69	CUSTOMER SERVICE CENTER REPRESENTATIVE III		1
70	COMMUNITY RELATIONS SPECIALIST		1
71	ASSOCIATE PROGRAM ADMINISTRATOR-EVALUATOR C&LM		1
72	ENERGY ENGINEER		1
73	ENERGY ENGINEER		1
74	SR PROGRAM ADMINISTRATOR-EVALUATOR		1
75	ADMINISTRATIVE ASSISTANT		1
76	PROGRAM ADMINISTRATOR-EVALUATOR		1
77	PROGRAM ADMINISTRATOR-EVALUATOR		1
78	MANAGER, IMPLEMENTATION		1
79	SENIOR ENERGY ENGINEER		1
80	IT DATABASE ADMINISTRATOR - LEVEL 4		1
81	PROGRAM ADMINISTRATOR-EVALUATOR		1
82	IT SECURITY ENGINEER LEVEL 3		1
83	IT SYSTEMS ENGINEER - LEVEL 3		1
84	IT SYSTEMS ENGINEER - LEVEL 3		1
85	Administrative Assistant, HR		1
86	Office Cleaner-Southern Dstrct		1
87	Expeditor Inspec		1
88	Senior Contract Agent		1
89	Supply Mgmt Technician Gr10		1
90	Lead Engineer		1
91	Manager, Load Forecasting		1
92	Labor Relations Coordinator		1
93	Community Relations Specialist		1
94	Com Rels Program Specialist		1
95	Senior Contract Agent		1
96	Senior Contract Agent		1
97	IT Security Engineer-Level 4		1
98	Material Handler		1
99	Director, Sol Design&Delivery		1
100	Office Cleaner-Southern Dstrct		1
101	IT Systems Engineer-Level 3		1
102	Checking Clerk Gr10		1

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NUSCO Shared Services*
Corporate & Administrative Labor Savings Exhibit
January 1, 2013 to December 31, 2013 Merger Attrition

Line	(A) Job Title	(B) 1/1/14 Company	(C) Employees
103	Route Coordinator A	[redacted]	1
104	Buyer-Planner		1
105	Operations Office Admin Gr8		1
106	Operations Office Admin Gr8		1
107	Material Handler		1
108	Buyer-Planner		1
109	Com Rels Program Specialist		1
110	Senior Compensation Analyst		1
111	Prog Manager, C&I Direct Instl		1
112	Prog Manager, C&I New Constrct		1
113	Program Manager		1
114	Program Manager		1
115	Senior Res Analyst, Enrgy Con		1
116	IT Bus App Sys Developer-Lvl 4		1
117	Senior Contract Agent		1
118	Manager, Real Estate Management		1
119	Labor Relations Consultant		1
120		**Exits 1/1/13 to 12/31/13:**	**-119**

Line	(A) Job Title	(B) 1/1/14 Company	(C) Employees
121	CUSTOMER SERVICES ASSISTANT (SW)	[redacted]	1
122	IT COMPUTER SECURITY TECHNICIAN - LEVEL 1		1
123	TECHNICAL ASSOCIATE		1
124	ANALYST		1
125	MATERIALS COORDINATOR-TRANSMISSION		1
126	LEAD HUMAN RESOURCES BUSINESS PARTNER		1
127	TAX ACCOUNTANT		1
128	HR COORDINATOR		1
129	SENIOR FINANCIAL ANALYST		1
130	TAX ACCOUNTANT		1
131	SENIOR TAX ACCOUNTANT		1
132	CONSTRUCTION REPRESENTATIVE-TRANSMISSION		1
133	SENIOR PROJECT COST ANALYST-TRANSMISSION		1
134	IT SECURITY ENGINEER LEVEL 3		1
135	ASSOCIATE SYSTEM OPERATIONS SUPERVISOR		1
136	ASSOCIATE SYSTEM OPERATIONS SUPERVISOR		1
137	EASEMENT COORDINATOR-DISTRIBUTION (SW)		1
138	PROGRAM MANAGER-RELIABILITY COMPLIANCE		1
139	ASSOCIATE SYSTEM OPERATIONS SUPERVISOR		1
140	IT BUSINESS APPLICATION SYSTEMS DEVELOPER- LEVEL 1		1
141	SOURCING CONSULTANT		1
142	ACCOUNT EXECUTIVE		1
143	ASSOCIATE TRANSMISSION MATERIAL ANALYST		1
144	ASSOCIATE SYSTEM OPERATIONS SUPERVISOR		1
145	ASSOCIATE STAFF ACCOUNTANT		1
146	ASSISTANT PROGRAM ADMINISTRATOR-EVALUATOR C&LM		1
147	DIRECTOR,IT PMO & ENTERPRISE ARCHITECTURE		1
148	SAFETY ANALYST		1
149	SUPERVISOR, FIELD SAFETY		1
150	BUYER		1
151	SENIOR STAFF ACCOUNTANT		1

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NUSCO Shared Services*
Corporate & Administrative Labor Savings Exhibit
January 1, 2013 to December 31, 2013 Merger Attrition

Line	(A) Job Title	(B) 1/1/14 Company	(C) Employees
152	INTERNAL AUDITOR	[redacted]	1
153	T&D TRAINING & WORK METHODS COORDINATOR		1
154	ASSOCIATE ENGINEER		1
155	DESIGN DRAFTER A		1
156	SUPERVISOR-BUSINESS SERVICES GROUP		1
157	ANALYST		1
158	COMMUNITY RELATIONS SPECIALIST		1
159	ASSOCIATE ENVIRONMENTAL COORDINATOR		1
160	COMMUNITY RELATIONS SPECIALIST		1
161	PROGRAM ADMINISTRATOR-EVALUATOR		1
162	PROGRAM ADMINISTRATOR-EVALUATOR		1
163	ENERGY ENGINEER		1
164	ENERGY ENGINEER		1
165	ASSISTANT PROGRAM ADMINISTRATOR-EVALUATOR C&LM		1
166	PROGRAM ADMINISTRATOR-EVALUATOR		1
167	ASSOCIATE PROGRAM ADMINISTRATOR-EVALUATOR		1
168	ASSOCIATE ENERGY ENGINEER		1
169	SENIOR ENERGY ENGINEER		1
170	MARKETING & CONSERVATION PROGRAM ADMINISTRATOR		1
171	ASSOCIATE MARKETING & CONSERVATION PROGRAM		1
172	ASSOCIATE ANALYST		1
173	ENERGY ENGINEER		1
174	ENERGY ENGINEER		1
175	LAND MANAGEMENT ADMINISTRATOR		1
176	TECHNICAL ASSOCIATE		1
177	SENIOR TAX ACCOUNTANT		1
178	MEDIA SPECIALIST		1
179	LEAD HR BUSINESS PARTNER		1
180	CLEARING DESK ASSOCIATE II (SW)		1
181	SENIOR COMMUNICATIONS SPECIALIST		1
182	ACCOUNTING SPECIALIST (CORPORATE)		1
183	ACCOUNTING SPECIALIST (CORPORATE)		1
184	Senior Contract Agent		1
185	Senior Environmental Engineer		1
186	Senior Environmental Engineer		1
187	Assoc Analyst-Revenue Forecast		1
188	Senior Contract Agent		1
189	Senior Revenue Require Analyst		1
190	Senior Communicatns Specialist		1
191	Senior Finan Analyst, Inv Plng		1
192	Senior Finan Analyst, Inv Plng		1
193	Senior Revenue Contrls Analyst		1
194	Senior Contract Agent		1
195	Counsel		1
196	Bldgs Maint Mechanic/Electricn		1
197	Community Relations Specialist		1
198	Analyst, Revenue Forecasting		1
199	Computer Technician		1
200	Contract Agent		1
201	Director, Revenue Requirements		1
202	Environmental Coordinator-MA		1
203	Supervising Engineer, Acct Spt		1

NUSCO Shared Services*
Corporate & Administrative Labor Savings Exhibit
January 1, 2013 to December 31, 2013 Merger Attrition

Line	(A) Job Title	(B) 1/1/14 Company	(C) Employees
204	Prog Manager Tech, C&I Implem	[redacted]	1
205	Executive Secretary		1
206	Energy Eff Sales Executive		1
207	Program Manager, C&I Retrofit		1
208	Prog Manager, C&I New Constrct		1
209	Prog Manager, C&I Direct Instl		1
210	Prog Manager Tech, C&I Implem		1
211	Prog Manager Tech, C&I Implem		1
212	Energy Eff Sales Executive		1
213	Program Manager, Res Implement		1
214	Proj Coordinator, Energy Effic		1
215	Vice President, Empl&Labor Rel		1
216	Senior Revenue Require Analyst		1
217	Product Manager, Energy Eff		1
218	Prog Manager, C&I New Constrct		1
219	Senior Revenue Require Analyst		1
220	Prog Manager Tech, C&I Implem		1
221	Marketg Database Administrator		1
222	Senior Analyst,Revenue Forecst		1
223	Com Rels Program Specialist		1
224		**Hires 1/1/13 to 12/31/3013:**	**103**
225		**Net Attrition:**	**-16**

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Merger-related attrition is the difference between the number of employee exits and the number of new hires for employees who performed shared services functions on a year-by-year basis.

Eversource Energy Service Company
Corporate & Administrative Labor Savings Exhibit
January 1, 2014 to December 31, 2014 Merger Reductions

							2014 Current Year Labor Savings							
Line	Job Title	1/1/14 Company Col. A	Head Count Col. B	Salary Col. C	Year End Date Col. D	Days in year after Term Date Col. E	2014 Salary Savings Col. F	Benefits Loader Col. G	Benefits Savings Col. H	Payroll Tax Loader	Payroll Tax Savings Col. I	Adjusted PR Tax Savings Col. J	Pension & PBOP Savings Col. K	Total Savings L=F+H+J+K
1	CREDIT COUNSELOR	[redacted]	1	$ [redacted]										
2	CREDIT COUNSELOR	[redacted]	1	$ [redacted]										
3	CREDIT COUNSELOR	[redacted]	1	$ [redacted]										
4	CREDIT COUNSELOR	[redacted]	1	$ [redacted]										
5	Power Plant Program Manager	[redacted]	1	$ [redacted]										
6	Admin Coordinator	[redacted]	1	$ [redacted]										
7	Fixed Asset Analyst	[redacted]	1	$ [redacted]										
8	Fixed Asset Analyst	[redacted]	1	$ [redacted]										
9	Fixed Asset Analyst	[redacted]	1	$ [redacted]										
10	Program Manager, Accounting	[redacted]	1	$ [redacted]										
11	Business Integration Manager	[redacted]	1	$ [redacted]										
12	Audit Manager, Cust Care & IT	[redacted]	1	$ [redacted]										
13	DIRECTOR EMPLOYEE RELATIONS	[redacted]	1	$ [redacted]										
14	PROJECT MANAGER	[redacted]	1	$ [redacted]										
15	SENIOR BUYERS ASSISTANT	[redacted]	1	$ [redacted]										
16	Supervisor, Purchasing	[redacted]	1	$ [redacted]										
17	TRANSMISSION CONTRACTS ASSISTANT (SW)	[redacted]	1	$ [redacted]										
18	MANAGER-TRANSMISSION CONTRACTS	[redacted]	1	$ [redacted]										
19	DIVISION MANAGER	[redacted]	1	$ [redacted]										
20	MANAGER-CUSTOMER OPERATIONS	[redacted]	1	$ [redacted]										
21		**Totals**	**20**	**$ 1,961,702**			**$ 765,364**		**$ 214,450**		**$ 60,882**	**$ 60,882**	**$ 84,176**	**$ 1,124,873**
		Totals By Company												
22		[redacted]	18	$ [redacted]			$ [redacted]		$ [redacted]		$ [redacted]			
23		[redacted]	-	$ [redacted]			$ [redacted]		$ [redacted]		$ [redacted]			
24		[redacted]	-	$ [redacted]			$ [redacted]		$ [redacted]		$ [redacted]			
25		[redacted]	1	$ [redacted]			$ [redacted]		$ [redacted]		$ [redacted]			
26		[redacted]	1	$ [redacted]			$ [redacted]		$ [redacted]		$ [redacted]			
27		Total	20	1,961,702			765,364		214,450		60,882	60,882	84,176	1,124,873

Eversource Energy Service Company
Corporate & Administrative Labor Savings Exhibit
January 1, 2014 to December 31, 2014 Merger Reductions

Line	Job Title	1/1/14 Company Col. A	Head Count Col. B	Salary Col. C	Year End Date Col. D	Days in year after Term Date Col. E	2014 Annualized Labor Savings: 2014 Salary Savings Col. M	Benefit Loader Col. N	Benefit Savings Col. O	Payroll Tax Loader	Payroll Tax Savings Col. P	Remove excess FICA in PR Tax Savings	Adjusted Tax Savings Col. Q	Pension & PBOP Savings Col. R	Total Savings S= M+O+Q+R
1	CREDIT COUNSELOR	[redacted]	1	$ [redacted]											
2	CREDIT COUNSELOR		1	$											
3	CREDIT COUNSELOR		1	$											
4	CREDIT COUNSELOR		1	$											
5	Power Plant Program Manager		1	$											
6	Admin Coordinator		1	$											
7	Fixed Asset Analyst		1	$											
8	Fixed Asset Analyst		1	$											
9	Fixed Asset Analyst		1	$											
10	Program Manager, Accounting		1	$											
11	Business Integration Manager		1	$											
12	Audit Manager, Cust Care & IT		1	$											
13	DIRECTOR EMPLOYEE RELATIONS		1	$											
14	PROJECT MANAGER		1	$											
15	SENIOR BUYERS ASSISTANT		1	$											
16	Supervisor, Purchasing		1	$											
17	TRANSMISSION CONTRACTS ASSISTANT (SW)		1	$											
18	MANAGER-TRANSMISSION CONTRACTS		1	$											
19	DIVISION MANAGER		1	$											
20	MANAGER-CUSTOMER OPERATIONS		1	$											
21		**Totals**	**20**	**$ 1,961,702**			**$ 1,961,702**		**$ 565,001**		**$ 155,198**	**$ (9,109)**	**$ 146,088**	**$ 243,040**	**$ 2,915,831**
		Totals By Company													
22		[redacted]	18	$ [redacted]			$ [redacted]		$ [redacted]		$ [redacted]				
23			-	$			$		$		$				
24			-	$			$		$		$				
25			1	$			$		$		$				
26			1	$			$		$		$				
27		Total	20	1,961,702			1,961,702		565,001		155,198	(9,109)	146,088	243,040	2,915,831

NUSCO Shared Services*
Corporate & Administrative Labor Savings Exhibit
January 1, 2014 to December 31, 2014 Merger Attrition

Line	(A) Job Title	(B) Legacy Company	(C) Employees
1	SR PROGRAM ADMINISTRATOR-EVALUATOR	[redacted]	1
2	SUPERVISOR, RESIDENTIAL RETROFIT		1
3	SENIOR ENERGY ENGINEER		1
4	SUPERVISOR-RESIDENTIAL C&LM		1
5	SUPERVISOR-ENERGY EFFICIENCY PROGRAMS		1
6	PROGRAM ADMINISTRATOR-EVALUATOR		1
7	SR PROGRAM ADMINISTRATOR-EVALUATOR		1
8	MARKETING & CONSERVATION PROGRAM ADMINISTRATOR		1
9	SENIOR LAND MANAGEMENT ADMINISTRATOR		1
10	ACCOUNTING SPECIALIST (CORPORATE)		1
11	SENIOR ANALYST		1
12	ASSOCIATE CASH MANAGEMENT ANALYST		1
13	SUPERVISOR, OPERATIONS SERVICES		1
14	LEARN & DEVELOP TECH CONSULTANT		1
15	MANAGER, LEADERSHIP & ORG DEVELOPMENT		1
16	PERFORMANCE CONSULTANT		1
17	SUPERVISOR-REVENUE PROTECTION		1
18	CLEARING DESK ASSOCIATE III (SW)		1
19	ACCOUNT EXECUTIVE		1
20	SENIOR METER OPERATIONS SPECIALIST		1
21	ACCOUNT EXECUTIVE		1
22	SENIOR COMMUNICATIONS SPECIALIST		1
23	MEDIA SPECIALIST		1
24	SENIOR ANALYST		1
25	SENIOR ENGINEER		1
26	MANAGER, RETAIL ACCESS PLANNING & SUPPORT		1
27	PROJECT MANAGER		1
28	DIRECTOR-SALES & MARKETING		1
29	MANAGER-HRIS		1
30	LEAD HUMAN RESOURCES BUSINESS PARTNER		1
31	MANAGER, STAFFING		1
32	WORKERS COMPENSATION ASSISTANT (SW)		1
33	SENIOR COUNSEL		1
34	INTERNAL AUDITOR		1
35	SENIOR COUNSEL		1
36	SENIOR REGULATORY PLANNING ANALYST		1
37	SENIOR ANALYST-TRANSMISSION		1
38	SENIOR FINANCIAL ANALYST		1
39	SENIOR REVENUE REQUIREMENTS ANALYST		1
40	DIRECTOR-REGULATORY AFFAIRS		1
41	MANAGER-SUPPLIER RELATIONS AND DIVERSITY		1
42	SENIOR BUYERS ASSISTANT		1
43	SENIOR ENVIRONMENTAL COORDINATOR		1
44	ANALYST-GENERAL SERVICES		1
45	MANAGER-OPERATIONS SUPPORT (WMECO)		1
46	ASSOCIATE ENVIRONMENTAL SPECIALIST		1
47	MANAGER, LICENSING & PERMITTING		1
48	SR ENVIRONMENTAL COORDINATOR		1
49	L&P SPECIALIST, CL&P		1
50	SUPERVISOR-MECHANICAL/ELECTRICAL SERVICES		1
51	PROJECT MANAGER-PROPERTY DEVELOPMENT		1
52	ASSOCIATE ENVIRONMENTAL COORDINATOR		1
53	TRANSMISSION MATERIAL ANALYST		1
54	ENVIRONMENTAL COORDINATOR		1

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NUSCO Shared Services*
Corporate & Administrative Labor Savings Exhibit
January 1, 2014 to December 31, 2014 Merger Attrition

Line	(A) Job Title	(B) Legacy Company	(C) Employees
55	MATERIALS COORDINATOR-TRANSMISSION	[redacted]	1
56	L&P SPECIALIST, CL&P		1
57	LIABILITY CLAIMS MANAGER-LEVEL 3		1
58	SENIOR CONSULTANT-PROPERTY TAX		1
59	TEAM LEADER		1
60	ASSOCIATE STAFF ACCOUNTANT		1
61	LOAD RESEARCH AND ISO REPORTING SUPERVISOR		1
62	SUPERVISOR-ENVIRONMENTAL OPERATIONS		1
63	BUSINESS ANALYST		1
64	SENIOR PROJECT COST ANALYST-TRANSMISSION		1
65	SENIOR CONSTRUCTION REPRESENTATIVE-TRANSMISSION		1
66	ADMINISTRATIVE ASSISTANT A (SW)		1
67	CONTRACT ADMINISTRATOR		1
68	ASSOCIATE CONTRACT ADMINISTRATOR		1
69	SENIOR PLANNER & SCHEDULER		1
70	ADMINISTRATIVE ASSISTANT (SW)		1
71	PROJECT DIRECTOR-TRANSMISSION		1
72	TRANSMISSION PLANNING SENIOR ENGINEER		1
73	TRANSMISSION PLANNING SENIOR ENGINEER		1
74	TRANSMISSION PLANNING SENIOR ENGINEER		1
75	EXECUTIVE ASSISTANT		1
76	TRANSMISSION PLANNING SENIOR ENGINEER		1
77	TRANSMISSION PROJECTS COORDINATOR		1
78	SUPERVISOR-CONVEX SYSTEM PRACTICES AND TRAINING		1
79	ENGINEERING TECHNICIAN A		1
80	TRANSMISSION OPERATIONAL PLANNING ENGINEER		1
81	LEAD PROJECT MANAGER-MUNICIPAL CONTRACTS		1
82	SENIOR SOURCING CONSULTANT		1
83	SENIOR SOURCING CONSULTANT		1
84	SENIOR ENGINEERING DESIGNER		1
85	SENIOR TEST SPECIALIST		1
86	ENGINEERING DESIGNER		1
87	SIMULATOR TRAINING SYSTEMS COORDINATOR-CONVEX		1
88	VICE PRESIDENT-TRANSMISSION PROJ ENGINEERING & MTN		1
89	ASSOCIATE ENGINEER		1
90	ASSISTANT ENGINEER		1
91	Supervisor, C&I Implementation		1
92	Program Manager, C&I Retrofit		1
93	Prog Manager, C&I New Constrct		1
94	Supervisor, C&I Implementation		1
95	Manager, Res & Low Income Prog		1
96	Program Manager, C&I Retrofit		1
97	Program Manager, C&I Retrofit		1
98	Senior Res Analyst, Enrgy Con		1
99	Program Manager, Res Implement		1
100	Program Manager, Res Implement		1
101	Energy Eff Sales Executive		1
102	Manager, Program Evaluation		1
103	Senior Business Analyst		1
104	Lead Load Estimation Engineer		1
105	Senior Supervisor, Inv Plg&Adm		1
106	Lead Revenue Analyst		1
107	Supervisor, Electric Ops		1
108	Accountant		1

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NUSCO Shared Services*
Corporate & Administrative Labor Savings Exhibit
January 1, 2014 to December 31, 2014 Merger Attrition

Line	(A) Job Title	(B) Legacy Company	(C) Employees
109	Senior Tax Acctg&Comp Special	[redacted]	1
110	Senior Revenue Require Analyst		1
111	Payroll Represent		1
112	Senior Revenue Require Analyst		1
113	Checking Clerk Gr10		1
114	Operations Office Admin Gr8		1
115	Operations Office Admin Gr8		1
116	Checking Clerk Gr10		1
117	Checking Clerk Gr10		1
118	Checking Clerk Gr10		1
119	Manager, Benefits Operations		1
120	Manager, Diversity & Inclusion		1
121	Lead HR Business Partner		1
122	Manager, HRIS		1
123	Senior Workers Comp Analyst		1
124	Trans Contracts Admin Analyst		1
125	Material Handler		1
126	Util Wrkr Bldg Mai A		1
127	Util Wrkr Bldg Mai A		1
128	Supervisor, Facilities Mgmt		1
129		**Exits 1/1/14 to 12/31/14:**	**-128**

Line	(A) Job Title	(B) Legacy Company	(C) Employees
130	ENERGY EFFICIENCY SALES EXECUTIVE	[redacted]	1
131	ASSISTANT MARKETING COORDINATOR		1
132	ASSOCIATE ANALYST		1
133	DIRECTOR, IMPLEMENTATION		1
134	SUPERVISOR-C&I RETROFIT		1
135	ASSISTANT MARKETING COORDINATOR		1
136	MAIL CENTER COMPUTER OPERATOR C		1
137	MEDIA SPECIALIST		1
138	STAFF ACCOUNTANT		1
139	ASSOCIATE FINANCIAL ANALYST		1
140	ASSOCIATE STAFF ACCOUNTANT		1
141	ACCOUNT EXECUTIVES-MID SIZE ACCOUNTS		1
142	COMMUNICATIONS SPECIALIST		1
143	MANAGER, HR CONSULTING		1
144	LEAD HUMAN RESOURCES BUSINESS PARTNER		1
145	INTERNAL AUDITOR		1
146	INTERNAL AUDITOR		1
147	ANALYST		1
148	COMMUNITY RELATIONS SPECIALIST		1
149	L&P SPECIALIST, CL&P		1
150	ASSOCIATE ENVIRONMENTAL COORDINATOR		1
151	ASSOCIATE ENVIRONMENTAL COORDINATOR		1
152	ASSOCIATE STAFF ACCOUNTANT		1
153	ASSOCIATE STAFF ACCOUNTANT		1
154	STAFF ACCOUNTANT		1
155	TAX ACCOUNTANT		1
156	SENIOR TAX ACCOUNTANT		1
157	SENIOR SOURCING CONSULTANT		1
158	SUPERVISOR, LOAD SETTLEMENT		1
159	MANAGER-SUPPLIER RELATIONS AND DIVERSITY		1

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NUSCO Shared Services*
Corporate & Administrative Labor Savings Exhibit
January 1, 2014 to December 31, 2014 Merger Attrition

Line	(A) Job Title	(B) Legacy Company	(C) Employees
160	ASSOCIATE ENVIRONMENTAL COORDINATOR	[redacted]	1
161	TRANSMISSION PLANNING SENIOR ENGINEER		1
162	ADMINISTRATOR-CONVEX SYSTEM PRACTICES & TRAINING		1
163	ENGINEERING DRAWING CONTROL SPECIALIST		1
164	ADMINISTRATIVE ASSISTANT (SW)		1
165	TEST SPECIALIST A		1
166	CONSTRUCTION REPRESENTATIVE-TRANSMISSION		1
167	PROJECT MANAGER-TRANSMISSION		1
168	TRANSMISSION PLANNING ENGINEER		1
169	TEST TECHNICIAN		1
170	SENIOR PLANNER & SCHEDULER		1
171	DESIGNER A		1
172	Program Manager, C&I Retrofit		1
173	Prog Manager, C&I Direct Instl		1
174	Prog Manager Tech, C&I Implem		1
175	Prog Manager, C&I Direct Instl		1
176	Prog Manager, C&I New Constrct		1
177	Prog Manager Tech, C&I Implem		1
178	Program Manager, Res Implement		1
179	Energy Eff Sales Executive		1
180	Senior Res Analyst, Enrgy Con		1
181	Energy Eff Sales Executive		1
182	Senior Res Analyst, Enrgy Con		1
183	Senior Media Rels Specialist		1
184	Senior Business Analyst		1
185	Associate Performance Analyst		1
186	Assoc Analyst,Revenue Forecast		1
187	Revenue Requirements Analyst		1
188	Manager, Diversity & Inclusion		1
189	Senior Staffing Consultant		1
190	Learn & Develop Tech Consultnt		1
191	Senior Labor Rels Consultant		1
192	Manager, Diversity & Inclusion		1
193	Learn & Develop Tech Consultnt		1
194	Manager, Total Rewards		1
195	Senior Right of Way Specialist		1
196	Senior Contract Agent		1
197	Environmental Coordinator-MA		1
198	Real Estate Analyst		1
199	Director, Procurement		1
200	Supervisor, Facilities Mgmt		1
201		**Hires 1/1/14 to 12/31/14:**	**71**
202		**Net Attrition:**	**-57**

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Merger-related attrition is the difference between the number of employee exits and the number of new hires for employees who performed shared services functions on a year-by-year basis.

NUSCO Shared Services*
Corporate & Administrative Labor Savings Exhibit
January 1, 2015 to September 30, 2015 Merger Reductions

Line	Job Title	1/1/14 Company Col. A	Head Count Col. B	Salary Col. C	Year End Date Col. D	Days in year after Term Date Col. E	2015 Current Year Labor Savings: 2015 Salary Savings Col. F	Benefits Loader Col. G	Benefits Savings Col. H	Payroll Tax Loader Col. I	Payroll Tax Savings	Adjusted PR Tax Savings Col. J	Pension & PBOP Savings Col. K	Total Savings L=F+H+J+K
1	Associate Accounting Analyst	[redacted]	1	$ [redacted]										
2	Senior Accounting Analyst		1	$										
3			**2**	**$ 148,886** (a)			**$ 148,886**		**$ 31,404**		**$ 13,698**	**$ 13,698**	**$ 31,982**	**$ 225,970**

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(a) Current year savings are calculated as if the savings was through December 31, 2015. Annual savings multiplied by .75 to prorate and only include savings through September 30, 2015 on ES-104, Page 1 Line 15 (E).

NUSCO Shared Services*
Corporate & Administrative Labor Savings Exhibit
January 1, 2015 to September 30, 2015 Merger Reductions

							2015 Annualized Labor Savings							
Line	**Job Title**	**1/1/14 Company Col. A**	**Head Count Col. B**	**Salary Col. C**	**Year End Date Col. D**	**Days in year after Term Date Col. E**	**2015 Salary Savings Col. M**	**Benefit Loader Col. N**	**Benefit Savings Col. O**	**Payroll Tax Loader Col. P**	**Payroll Tax Savings**	**Adjusted Tax Savings Col. Q**	**Pension & PBOP Savings Col. R**	**Total Savings S=M+O+Q+R**
1	Associate Accounting Analyst	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	Senior Accounting Analyst	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3			**2**	**$ 148,886**			**$ 148,886**		**$ 31,404**		**$ 13,698**	**$ 13,698**	**$ 31,982**	**$ 225,970**

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PUBLIC VERSION
PROTECTED MATERIALS REDACTED

NUSCO Shared Services*
Corporate & Administrative Labor Savings Exhibit
January 1, 2015 to September 30, 2015 Merger Attrition

Line	(A) Job Title	(B) Legacy Company	(C) Employees
1	Accountant A	[redacted]	1
2	Accountant A		1
3	Director Rev & Reg Acctng		1
4	MANAGER, TAXES		1
5	Energy Eff Sales Executive		1
6	SUPERVISOR-CUSTOMER BILLING & ACCOUNTING		1
7	MANAGER-BUSINESS CENTER		1
8	ACCOUNT EXECUTIVES-MID SIZE ACCOUNTS		1
9	MAIL CENTER COMPUTER OPERATOR B		1
10	C&LM ADMINISTRATOR (SW)		1
11	PROGRAM EVALUATION-MEASUREMENT & VERIFICATION ADMS		1
12	SUPERVISOR-C&I RETROFIT		1
13	MANAGER-METER OPERATIONS		1
14	Manager Labor Relations		1
15	C&Lm Administrator (Sw)		1
16	Energy Engineer		1
17	Program Manager C&I Retrofit		1
18	Supervising Engineer C&I Impl		1
19	Analyst		1
20	MANAGER, BUDGET & INVEST PLNG		1
21	VICE PRESIDENT, BUS FINAN & CORP PERF MGMT		1
22	PERFORMANCE CONSULTANT		1
23	DIRECTOR, ENTERPRISE RISK MANAGEMENT		1
24	ACCOUNTANT A		1
25	SENIOR STAFF ACCOUNTANT		1
26	DIRECTOR, RATES & LOAD FORECASTING		1
27	STAFF ACCOUNTANT		1
28	SENIOR REGULATORY PLANNING ANALYST		1
29	SENIOR TAX ACCOUNTANT		1
30	Analyst		1
31	Business Intelligence Analyst		1
32	Manager Budget & Invest Plng		1
33	Manager, Budget & Invest Plng		1
34	Sr Finan Analyst, Invest Plng		1
35	Project Manager		1
36	PROGRAM MANAGER-EMPLOYEE RELATIONS		1
37	SENIOR ORGANIZATIONAL DEVELOPMENT CONSULTANT		1
38	Manager, Labor Relations		1
39	Manager Compensation		1
40	Senior HRIS Specialist		1
41	Assistant General Counsel		1
42	Senior Counsel		1
43	Senior Counsel		1
44	PROGRAM MANAGER, RES IMPLEMENT		1
45	PRIN SUPPLY CHAIN ANALYST		1
46	DIRECTOR-BUDGETS & INVESTMENT PLANNING		1
47	C&LM ADMINISTRATOR (SW)		1
48	CLEARING DESK ASSOCIATE III (SW)		1
49	PROJECT MANAGER		1
50	SUPERVISOR-BUSINESS CONTACT CENTER		1
51	ADMINISTRATIVE ASSISTANT A		1
52	SENIOR COMMUNICATIONS SPECIALIST		1

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NUSCO Shared Services*
Corporate & Administrative Labor Savings Exhibit
January 1, 2015 to September 30, 2015 Merger Attrition

Line	(A) Job Title	(B) Legacy Company	(C) Employees
53	ASSOCIATE ENERGY ENGINEER	[redacted]	1
54	DIRECTOR-FINANCIAL PLNG ANALYSIS & TRANSACTION SUP		1
55	MANAGER, FINANCIAL ANALYSIS		1
56	HEALTH UNIT ASSISTANT (SW)		1
57	LEGAL ADMINISTRATIVE ASSISTANT (SW)		1
58	BUYER		1
59	SUPERVISOR-TENANT SERVICES		1
60	EXECUTIVE DIRECTOR, ES BOULOS		1
61	TRANSMISSION PROJECT MANAGEMENT SPECIALIST		1
62	DIRECTOR-CLAIMS AND INSURANCE		1
63	ACCOUNTANT A		1
64	ASSOCIATE ACCOUNTANT		1
65	INVOICE ACCOUNTING ASSISTANT A		1
66	STAFF ACCOUNTANT		1
67	TEAM LEADER		1
68	TRANSMISSION OPERATIONAL PLANNING ENGINEER		1
69	Assoc Revenue Require Analyst		1
70	Director, Rates		1
71	TEAM LEADER		1
72	Team Leader		1
73	Senior Right of Way Specialist		1
74	Administrative Assistant A		1
75	Material Coordinator		1
76	Material Coordinator		1
77	Project Siting & Permitting Specialist		1
78	Senior Contract Agent		1
79	Senior Contract Agent		1
80	Senior Contract Agent		1
81	Senior Right of Way Specialist		1
82	Senior Sourcing Consultant		1
83	Senior Sourcing Consultant		1
84	Sourcing Manager		1
87	L&P SPECIALIST, CL&P		1
88	SENIOR ANALYST-REAL ESTATE		1
89	EXPRESS DRIVER		1
90	MANAGER-NEPOOL AND ISO RELATIONS		1
88	MANAGER-TRANSMISSION LINE CONSTRUCTION & MTCE		1
89	MANAGER-TRANSMISSION SUBSTATION MAINT		1
90	ADMINISTRATIVE ASSISTANT (SW)		1
91	TRANSMISSION PLANNING SENIOR ENGINEER		1
89	ADMINISTRATIVE ASSISTANT (SW)		1
90	Senior Nerc Compliance Specialist		1
91	Lead Equipment Analyst		1
92	Lead Project Manager-Transmission Projects		1
90	Project Manager Level 1-Transmission		1
91	MANAGER-TRANSMISSION INTERCONNECTIONS & SERVICES		1
92	Project Manager-Siting (MA & NH)		1
93	Project Siting Specialist		1
91	TRANSMISSION COORDINATOR		1
92	Administrative Assistant (SW)		1
85	Transmission Material Analyst		1
86	ENVIRONMENTAL SPECIALIST		1
93		**Exits 1/1/15 to 9/30/15:**	**-104**

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PUBLIC VERSION
PROTECTED MATERIALS REDACTED

NUSCO Shared Services*
Corporate & Administrative Labor Savings Exhibit
January 1, 2015 to September 30, 2015 Merger Attrition

Line	(A) Job Title	(B) Legacy Company	(C) Employees
94	Energy Eff Sales Executive	[redacted]	1
95	Senior Res Analyst, Enrgy Con		1
96	CLEARING DESK ASSOCIATE III (SW)		1
97	PROGRAM ADMINISTRATOR-EVALUATOR		1
98	ANALYST		1
99	ASSOCIATE REVENUE REQUIREMENTS ANALYST		1
100	TEAM LEADER		1
101	Senior Counsel		1
102	PARALEGAL		1
103	Material Planning Analyst		1
104	Prin Supply Chain Analyst		1
105	TEST TECHNICIAN		1
106	ACCOUNT EXECUTIVE		1
107	Administrator, C&LM (SW)		1
108	ANALYST		1
109	Analyst, Pricing I		1
110	Associate Engineer, Energy		1
111	Associate Program Administrator-Evaluator		1
112	ASSOCIATE STAFF ACCOUNTANT		1
113	ASSOCIATE STAFF ACCOUNTANT		1
114	ASSOCIATE SYSTEM OPERATIONS SUPERVISOR		1
115	ASSOCIATE SYSTEM OPERATIONS SUPERVISOR		1
116	ASSOCIATE SYSTEM OPERATIONS SUPERVISOR		1
117	Category Lead		1
118	DIRECTOR, DIGITSTRAT&CHANMGMT		1
119	Director, Environmental Affairs		1
120	Director, Project Planning and Siting		1
121	ENVIRONMENTAL ENGINEER		1
122	Environmental Specialist		1
123	ENVIRONMENTAL SPECIALIST		1
124	Financial Analyst		1
125	LABOR RELATIONS COORDINATOR		1
126	Manager, Gas Compliance and Risk Management		1
127	Manager, Taxes		1
128	Planner, Facilities		1
129	Principal Analyst, Supply Chain		1
130	Program Administrator, Evaluator		1
131	Program Manager, Commercial and Industrial Implementation		1
132	PROGRAM MANAGER, C&I RETROFIT		1
133	Program Manager, Commercial and Industrial Retrofit		1
134	PROJECT SITING SPECIALIST		1
135	Real Estate Agent		1
136	Sales Executive, Energy Efficiency		1
137	Senior Agent, Contract		1
138	Senior Analyst I		1
139	Senior Analyst, Energy Supply		1
140	SENIOR RES ANALYST, CUST SYS		1
141	Senior Specialist, Right of Way		1
142	Senior, Financial Analyst		1
143	Sourcing Agent		1
144	Specialist, Revenue Assurance		1
145	Supervisor, Energy Efficiency Programs		1

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NUSCO Shared Services*
Corporate & Administrative Labor Savings Exhibit
January 1, 2015 to September 30, 2015 Merger Attrition

Line	(A) Job Title	(B) Legacy Company	(C) Employees
146	SUPERVISOR, QUALITY ASSURANCE-QUALITY CONTROL	[redacted]	1
147	Tax Accountant		1
148	Tax Accountant		1
149	TECHNICAL ASSOCIATE		1
150	Technician B, Construction Services Support Center		1
151		**Hires 1/1/15 to 9/30/15:**	**57**
152		**Net Attrition:**	**-47**

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Merger-related attrition is the difference between the number of employee exits and the number of new hires for employees who performed shared services functions on a year-by-year basis.

Exhibit No. ES-106

Information Systems Savings Exhibit

Eversource Energy Service Company

Eversource Energy Service Company
Information Systems Savings Exhibit

	(A)		(B) 2012		(C) 2013		(D) 2014		(E) 2015		(F) Total
			Savings								
1	Savings		$ 409,393	(a)	$ 436,499	(b)	$ 4,777,119	(c)	$ 16,740,290	(d)	
2	Total Information Systems Savings:		$ 409,393	(e)	$ 436,499	(e)	$ 4,777,119	(e)	$ 12,555,218	(f)	$ 18,178,228

	(G) Allocation to Transmission:	(H) Allocation %		(I)= (B), Ln 11 *(H) 2012	(J)= (C), Ln 11 *(H) 2013	(K)= (D), Ln 11 *(H) 2014	(L)= (E), Ln 11 *(H) 2015	(M)= (I)+ (J) + (K) + (L) Total
3	CL&P	13.06%	(g)	$ 53,467	$ 57,007	$ 623,892	$ 1,639,711	$ 2,374,077
4	NSTAR Electric	6.64%	(g)	$ 27,184	$ 28,984	$ 317,201	$ 833,666	$ 1,207,034
5	PSNH	2.82%	(g)	$ 11,545	$ 12,309	$ 134,715	$ 354,057	$ 512,626
6	WMECO	2.50%	(g)	$ 10,235	$ 10,912	$ 119,428	$ 313,880	$ 454,456
7	**Total Transmission (Sum Ln 3- Ln 6)**	25.02%		$ 102,430	$ 109,212	$ 1,195,235	$ 3,141,315	$ 4,548,193

(a) Exhibit No. ES-106, Page 2, Line 7 (B)
(b) Exhibit No. ES-106, Page 2, Line 7 (C)
(c) Exhibit No. ES-106, Page 2, Line 7 (D)
(d) Exhibit No. ES-106, Page 2, Line 7 (E)
(e) Exhibit No. ES-103, Page 4, Line 6
(f) Annual savings multiplied by .75 to prorate and only include savings through September 30, 2015
(g) Source is Exhibit No. ES-112

Eversource Energy Service Company
Information Systems Savings Exhibit

	(A) Description		(B) 2012		(C) 2013		(D) 2014			(E) 2015 (a)	
	Information Systems Reorganization:										
1	Outside Services, net Savings (Cost)	$	-	$	-	$	(12,009,979)	(b)	$	(14,536,149)	(e)
2	Employee Salary Savings	$	-	$	-	$	9,769,844	(c)	$	18,604,403	(f)
3	Employee Benefits Savings	$	-	$	-	$	6,553,132	(d)	$	12,202,995	(g)
4	**Total Information Systems Reorganization Savings : (Ln 1 + Ln 2 + Ln 3)**	$	-	$	-	$	4,312,997		$	16,271,249	
	Other Information Systems Savings:										
5	NSTAR Passport Maintenance Fee Savings	$	409,393	$	415,780	$	422,058		$	426,532	
6	Claims Management System Consolidation	$	-	$	20,719	$	42,064		$	42,510	
7	**Total Information Systems Savings (Ln 4 + Ln 5 + Ln 6)**	$	409,393	$	436,499	$	4,777,119		$	16,740,290	

(a) 2015 savings are calculated through September 30, 2015.
(b) Exhibit No. ES-106, Page 3, Line 6 (B)
(c) Exhibit No. ES-106, Page 4, Line 1 (B)
(d) Exhibit No. ES-106, Page 4, Line 2 (B)
(e) Exhibit No. ES-106, Page 3, Line 6 (C)
(f) Exhibit No. ES-106, Page 4, Line 1, (C)
(g) Exhibit No. ES-106, Page 4, Line 2 (C)

Eversource Energy Service Company
Information Systems Savings Exhibit

	(A) Outside Services	(B) 2014	(C) 2015	
1	**Baseline Contractor Costs** (a)	$ 12,292,324	$ 12,422,623	*
	New Contractor Costs			
2	[redacted]	$ 5,630,632	$ -	
3		$ 14,005,650	$ 20,354,475	
4		$ 4,666,021	$ 6,604,297	
5	**Total New Contractor Costs (Ln 2 + Ln 3 + Ln 4)**	$ 24,302,303	$ 26,958,772	
6	**Total Outside Services net Savings (Costs) (Ln 1- Ln 5)**	**$ (12,009,979)**	**$ (14,536,149)**	

(a) NSTAR pre-merger [redacted] Contract

*These costs represent annualized 2015 costs. Please note, however, that on Page 1 these costs are prorated such that Eversource's savings analysis only considers savings and costs through September 30, 2015.

Eversource Energy Service Company
Information Systems Savings Exhibit

	(A) Description	(B) 2014		(C) 2015	
1	Employee Salary Savings	$ 9,769,844	(a)	$ 18,604,403	(c)
2	Employee Benefits Savings	$ 6,553,132	(b)	$ 12,202,995	(d)
3	Total Employee Salary & Benefits Savings (Ln 1+ Ln 2)	$ 16,322,976		$ 30,807,398	

(a) 2014 Salaries calculated by Exhibit No. ES-106, Page 5 (Line 17 (B) + Line 18 (B))
(b) 2014 Benefits calculated by Exhibit No. ES-106, Page 5, Line 19 (B)
(c) 2015 Salaries calculated by Exhibit No. ES-106, Page 5, Line 21 (B)*(1+3% Wage Growth) + Exhibit No. ES-106, Page 5, Line 17 (C)
(d) 2015 Benefits calculated by Exhibit No. ES-106, Page 5, Line 22 (B) +Line 23 (B)*(1+3% Wage Growth)) + Exhibit No. ES-106,

NUSCO*
Information Systems Savings Exhibit

	(A) Current Year	(B) 2014		(C) 2015 (a)	
1	Merger Related Employee Reductions	153		13	
2	Current Year Merger Reduction Salary Savings	$ 9,240,836		$ 1,481,989	
3	Current Year Merger Reduction Benefits Savings	$ 5,194,284		$ 649,337	
4	Total Current Year Merger Reduction Savings (Ln 2 + Ln 3)	$ 14,435,120	(b)	$ 2,131,326	(c)
5	Annual Merger Reduction Salary Savings	$ 15,350,918		$ 1,514,420	
6	Annual Merger Reduction Loader Savings	$ 8,553,268		$ 661,961	
7	Total Annual Merger Reduction Savings (ln 5 + ln 6)	$ 23,904,186	(d)	$ 2,176,381	(e)
8	Attrition Related Reductions	12	(f)	5	(g)
9	Salary (h)	$ 88,168		$ 88,485	
10	Current Year Attrition Salary Savings (i)	$ 529,008		$ 221,213	
11	Current Year Attrition Benefits Savings (j)	$ 303,253		$ 106,989	
12	Total Current Year Attrition Savings (Ln 10 + Ln 11)	$ 832,261		$ 328,201	
13	Annual Salary Attrition Savings (Ln 8 * Ln 9)	$ 1,058,016		$ 442,425	
14	Annual Attrition Benefits Savings	$ 606,506	(j)	$ 213,687	(k)
15	Total Annual Attrition Savings (Ln 13 + Ln 14)	$ 1,664,522		$ 656,112	
16	Total Current Year Employee Savings (Ln 1 + Ln 8)	165		18	
17	Total Current Year Salary Savings (Ln 2 + Ln 10)	$ 9,769,844		$ 1,703,202	
18	Total Current Year Incentive Pay Savings (k)	$ 1,055,595		$ 185,990	
19	Total Current Year Benefit Savings (Ln 3 + Ln 11)	$ 5,497,537		$ 756,325	
20	Total Current Year Savings (Ln 17 + Ln 18 + Ln 19)	$ 16,322,976		$ 2,645,517	
21	Annual Salary Employee Savings (Ln 5 + Ln 13)	$ 16,408,934		$ 1,956,845	
22	Annual Incentive Pay Savings (k)	$ 1,772,925		$ 213,687	
23	Annual Employee Benefits Savings (Ln 6 + Ln 14)	$ 9,159,774		$ 875,649	
24	Total Annual Employee Savings (Ln 21 + Ln 22 + Ln 23)	$ 27,341,632		$ 3,046,181	
	Cumulative Total				
25	Cumulative employee reductions (PY Ln 25 + CY Ln 16)	165		183	
26	**Cumulative labor savings with wage growth/inflation (PY Ln 24 + Ln 20 +3% Wage Growth)**	**$ 16,322,976**		**$ 30,807,398**	

*On July 1, 2015, Northeast Utilities Service Company's (NUSCO) legal name was changed to Eversource Energy Service Company.

(a) 2015 savings are calculated through September 30, 2015.
(b) Exhibit No. ES-106, Page 10, Ln 154 (L)
(c) Exhibit No. ES-106, Page 16, Ln 14 (L)
(d) Exhibit No. ES-106, Page 14, Ln 154 (S)
(e) Exhibit No. ES-106, Page 17, Ln 14 (S)
(f) Exhibit No. ES-106, Page 15, Ln 29 (C)
(g) Exhibit No. ES-106, Page 18, Ln 14 (C)
(h) Salary is based on an average salary of offsetting hires
(i) Exhibit No. ES-106, Page 6, Ln 9
(j) Exhibit No. ES-106, Page 6, Ln 15
(k) Exhibit No. ES-106, Page 6, Ln 12

NUSCO*
Information Systems Savings Exhibit
Calculation of Employee Savings-NUSCO

2014

Ln	(A)	(B)	(C)
	Attrition Related Reductions		
1	Number (a)		12
2	Annual Salary (b)		$ 88,168
	Benefits/Taxes/Pension Costs:		
3	Weighted Average Benefits Loader Rate (c)		33.76%
4	Weighted Average Payroll Tax Rate-NUSCO (d)		8.05%
5	Weighted Average Pension & PBOP Service Cost (e)		$ 13,687
6	Incentive Pay Percent (f)		10.00%
7	Pay Incentive with Tax-NUSCO(Ln 6*(1+Ln 4))		10.80%

Ln		CURRENT YEAR (CY)	ANNUALIZED (A)
8	Annual Salary Attrition(Ln 1 * Ln 2)	$ 1,058,016	$ 1,058,016
9	Attrition Salary Savings (Ln 8/2)	$ 529,008	$ 1,058,016
10	Merger Reduction Salary Savings (g)	$ 9,240,836	$ 15,350,918
11	Salary Savings (Ln 9+10)	$ 9,769,844	$ 16,408,934
12	Incentive Pay Savings (Ln 11* Ln 7)	$ 1,055,595	$ 1,772,925
13	Benefits & PR Tax (Ln 9*(Ln 3+4)	$ 221,133	$ 442,266
14	PBOP (Ln 1* Ln 5/2)	$ 82,120	$ 164,240
15	Attrition Benefits Savings (Ln 13+14)	$ 303,253	$ 606,506
16	Merger Reduction Benefits Savings (g)	$ 5,194,284	$ 8,553,268
17	Benefit Savings (Ln 19+20)	$ 5,497,537	$ 9,159,774
18	**Total Employee Savings (Sum Ln 15+Ln 16+ Ln 21)**	**$ 16,322,976**	**$ 27,341,632**

2015

Ln	(D)	(E)	(F)
	Attrition Related Reductions		
1	Number (h)		5
2	Annual Salary (b)		$ 88,485
	Benefits/Taxes/Pension Costs:		
3	Weighted Average Benefits Loader Rate (c)		21.09%
4	Weighted Average Payroll Tax Rate-NUSCO (d)		9.20%
5	Weighted Average Pension & PBOP Service Cost (e)		$ 15,991
6	Incentive Pay Percent (f)		10.00%
7	Pay Incentive with Tax-NUSCO(Ln 6*(1+Ln 4))		10.92%

Ln		CURRENT YEAR (CY)	ANNUALIZED (A)
8	Annual Salary Attrition(Ln 1 * Ln 2)	$ 442,425	$ 442,425
9	Attrition Salary Savings (Ln 8/2)	$ 221,213	$ 442,425
10	Merger Reduction Salary Savings (i)	$ 1,481,989	$ 1,514,420
11	Salary Savings (Ln 9+10)	$ 1,703,202	$ 1,956,845
12	Incentive Pay Savings (Ln 11* Ln 7)	$ 185,990	$ 213,687
13	Benefits & PR Tax (Ln 9*(Ln 3+4)	$ 67,011	$ 134,022
14	PBOP (Ln 1* Ln 5/2)	$ 39,978	$ 79,956
15	Attrition Benefits Savings (Ln 13+14)	$ 106,989	$ 213,978
16	Merger Reduction Benefits Savings (i)	$ 649,337	$ 661,961
17	Benefit Savings (Ln 19+20)	$ 756,325	$ 875,939
18	**Total Employee Savings (Sum Ln 15+Ln 16+ Ln 21)**	**$ 2,645,517**	**$ 3,046,471**

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(a) Exhibit No. ES-106, Page 15, Line 29 (C)
(b) Salary is based on an average salary of offsetting hires.
(c) Weighted Average Benefit Loader Rate was calculated as the ratio of health benefit costs to total labor costs in the given year based on queries of Eversource accounting database.
(d) Weighted Average Payroll Tax Rate was calculated as the ratio of employee payroll taxes to total labor costs in the given year based on queries of Eversource accounting database.
(e) Weighted Average Pension and PBOP Service Costs is the average pension and postretirement benefits other than pension (PBOP) cost per employee based on data from Eversource actuarial reports for the given year.
(f) Incentive Pay Percent is based on an average target incentive pay in the given year.
(g) Exhibit No. ES-106, Page 10(CY), Page 14(A), Line 154
(h) Exhibit No. ES-106, Page 18, Line 14 (C)
(i) Exhibit No. ES-106, Page 16(CY), Page 17(A), Line 14

NUSCO*
Information Systems Savings Exhibit
January 1, 2014 to December 31, 2014 Merger Reductions

							2014 Current Year Labor Savings							
Line	Title	1/1/14 Company Col. A	Head count Col. B	Salary Col. C	Year End Date Col. D	Days in year after Term Date Col. E	2014 Salary Savings Col. F	Benefits Loader Col. G	Benefits Savings Col. H	Payroll Tax Loader Col. I	Payroll Tax Savings	Adjusted PR Tax Savings Col. J	Pension & PBOP Savings Col. K	Total Savings L=F+H+J+K
1	IT Systems Engineer-Level 3	[redacted]	1	$ [redacted]										
2	Senior Planning Analyst	[redacted]	1	$ [redacted]										
3	IT Bus App Sys Developer-Lvl 3	[redacted]	1	$ [redacted]										
4	IT Bus App Sys Developer-Lvl 4	[redacted]	1	$ [redacted]										
5	IT Project Manager-Level 3	[redacted]	1	$ [redacted]										
6	IT Supervisor-Appl Development	[redacted]	1	$ [redacted]										
7	IT Bus App Sys Developer-Lvl 4	[redacted]	1	$ [redacted]										
8	IT Database Administratr-Lvl 4	[redacted]	1	$ [redacted]										
9	IT Systems Engineer-Level 4	[redacted]	1	$ [redacted]										
10	IT Supervisor, X86	[redacted]	1	$ [redacted]										
11	IT Bus App Sys Developer-Lvl 4	[redacted]	1	$ [redacted]										
12	IT Bus App Sys Developer-Lvl 4	[redacted]	1	$ [redacted]										
13	IT Systems Engineer-Level 3	[redacted]	1	$ [redacted]										
14	IT Supervisor-Appl Development	[redacted]	1	$ [redacted]										
15	IT Systems Engineer-Level 4	[redacted]	1	$ [redacted]										
16	IT Bus App Sys Developer-Lvl 4	[redacted]	1	$ [redacted]										
17	Solutions Architect	[redacted]	1	$ [redacted]										
18	IT Supervisor, UNIX	[redacted]	1	$ [redacted]										
19	IT Database Administratr-Lvl 4	[redacted]	1	$ [redacted]										
20	IT Supervisor-Appl Development	[redacted]	1	$ [redacted]										
21	IT SYSTEMS ENGINEER - LEVEL 3	[redacted]	1	$ [redacted]										
22	LEVEL 2	[redacted]	1	$ [redacted]										
23	IT SYSTEMS ENGINEER - LEVEL 4	[redacted]	1	$ [redacted]										
24	IT VOICE COMMUNICATIONS ANALYST - LEVEL 3	[redacted]	1	$ [redacted]										
25	LEVEL 4	[redacted]	1	$ [redacted]										
26	LEVEL 1	[redacted]	1	$ [redacted]										
27	COORDINATOR	[redacted]	1	$ [redacted]										
28	QUALITY ASSURANCE SPECIALIST	[redacted]	1	$ [redacted]										
29	IT BUSINESS SOLUTIONS ANALYST-LEVEL 4	[redacted]	1	$ [redacted]										
30	LEVEL 3	[redacted]	1	$ [redacted]										
31	IT WEBMASTER - LEVEL 3	[redacted]	1	$ [redacted]										
32	IT PROJECT COORDINATOR - LEVEL 4	[redacted]	1	$ [redacted]										
33	IT TECHNICIAN-LEVEL 2	[redacted]	1	$ [redacted]										
34	IT CONSULTANT-LEVEL 1	[redacted]	1	$ [redacted]										
35	IT SYSTEMS ENGINEER - LEVEL 2	[redacted]	1	$ [redacted]										
36	LEVEL 3	[redacted]	1	$ [redacted]										
37	LEVEL 1	[redacted]	1	$ [redacted]										
38	LEVEL 4	[redacted]	1	$ [redacted]										
39	LEVEL 3	[redacted]	1	$ [redacted]										
40	LEVEL 4	[redacted]	1	$ [redacted]										
41	IT SYSTEMS ENGINEER - LEVEL 4	[redacted]	1	$ [redacted]										
42	IT WEBMASTER - LEVEL 3	[redacted]	1	$ [redacted]										
43	IT Net Analyst -LAN/WAN-Level 4	[redacted]	1	$ [redacted]										
44	IT TECHNOLOGY MANAGER	[redacted]	1	$ [redacted]										
45	IT SYSTEMS ENGINEER - LEVEL 4	[redacted]	1	$ [redacted]										
46	LEVEL 3	[redacted]	1	$ [redacted]										
47	IT PROJECT MANAGER - LEVEL 2	[redacted]	1	$ [redacted]										
48	IT DATABASE ADMINISTRATOR - LEVEL 4	[redacted]	1	$ [redacted]										

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PUBLIC VERSION
PROTECTED MATERIALS REDACTED

NUSCO*
Information Systems Savings Exhibit
January 1, 2014 to December 31, 2014 Merger Reductions

Line	Title	1/1/14 Company Col. A	Head count Col. B	Salary Col. C	Year End Date Col. D	Days in year after Term Date Col. E	2014 Current Year Labor Savings 2014 Salary Savings Col. F	Benefits Loader Col. G	Benefits Savings Col. H	Payroll Tax Loader Col. I	Payroll Tax Savings	Adjusted PR Tax Savings Col. J	Pension & PBOP Savings Col. K	Total Savings L=F+H+J+K
49	LEVEL 4	[redacted]	1	$ [redacted]										
50	IT DATABASE ADMINISTRATOR - LEVEL 3		1	$										
51	IT CONSULTANT-LEVEL 1		1	$										
52	3		1	$										
53	IT SYSTEMS ENGINEER - LEVEL 4		1	$										
54	LEVEL 3		1	$										
55	LEVEL 3		1	$										
56	LEVEL 4		1	$										
57	LEVEL 3		1	$										
58	IT SYSTEMS ENGINEER - LEVEL 4		1	$										
59	IT SYSTEMS ENGINEER - LEVEL 3		1	$										
60	IT CLIENT SERVICES REPRESENTATIVE - LEVEL 4		1	$										
61	LEVEL 4		1	$										
62	LEVEL 3		1	$										
63	LEVEL 4		1	$										
64	LEVEL 3		1	$										
65	LEVEL 3		1	$										
66	IT SYSTEMS ENGINEER - LEVEL 4		1	$										
67	IT SYSTEMS ENGINEER - LEVEL 4		1	$										
68	IT CLIENT SERVICES REPRESENTATIVE - LEVEL 3		1	$										
69	LEVEL 3		1	$										
70	IT TECHNICIAN-LEVEL 3		1	$										
71	LEVEL 4		1	$										
72	LEVEL 3		1	$										
73	IT SYSTEMS ENGINEER - LEVEL 4		1	$										
74	LEVEL 3		1	$										
75	LEVEL 3		1	$										
76	IT COMPUTER OPERATORS - LEVEL 3 (SW)		1	$										
77	3		1	$										
78	IT SYSTEMS ENGINEER - LEVEL 3		1	$										
79	LEVEL 3		1	$										
80	LEVEL 3		1	$										
81	LEVEL 4		1	$										
82	IT TECHNOLOGY MANAGER		1	$										
83	IT TECHNOLOGY MANAGER		1	$										
84	IT PRODUCT MANAGER LEVEL 3		1	$										
85	IT PROCESS ANALYST-LEVEL 3		1	$										
86	IT VOICE COMMUNICATIONS ANALYST - LEVEL 3		1	$										
87	IT SUPPORT CENTER CONSULTANT - LEVEL 3		1	$										
88	IT SYSTEMS ENGINEER - LEVEL 4		1	$										
89	IT SYSTEMS ENGINEER - LEVEL 4		1	$										
90	IT SYSTEMS ENGINEER - LEVEL 3		1	$										
91	IT DATABASE ADMINISTRATOR - LEVEL 4		1	$										
92	IT SYSTEMS ENGINEER - LEVEL 3		1	$										
93	LEVEL 3		1	$										
94	IT SYSTEMS ENGINEER - LEVEL 4		1	$										
95	IT SUPERVISOR, COMPUTER OPERATIONS		1	$										
96	IT CONSULTANT		1	$										

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NUSCO*
Information Systems Savings Exhibit
January 1, 2014 to December 31, 2014 Merger Reductions

							2014 Current Year Labor Savings							
Line	Title	1/1/14 Company Col. A	Head count Col. B	Salary Col. C	Year End Date Col. D	Days in year after Term Date Col. E	2014 Salary Savings Col. F	Benefits Loader Col. G	Benefits Savings Col. H	Payroll Tax Loader Col. I	Payroll Tax Savings	Adjusted PR Tax Savings Col. J	Pension & PBOP Savings Col. K	Total Savings L=F+H+J+K
97	IT SYSTEMS ENGINEER - LEVEL 3	[redacted]	1	$ [redacted]										
98	LEVEL 4	[redacted]	1	$ [redacted]										
99	IT SECURITY ENGINEER LEVEL 4	[redacted]	1	$ [redacted]										
100	LEVEL 3	[redacted]	1	$ [redacted]										
101	LEVEL 4	[redacted]	1	$ [redacted]										
102	LEVEL 4	[redacted]	1	$ [redacted]										
103	IT NETWORK SYSTEMS ENGINEER - LEVEL 4	[redacted]	1	$ [redacted]										
104	LEVEL 3	[redacted]	1	$ [redacted]										
105	LEVEL 4	[redacted]	1	$ [redacted]										
106	IT INFORMATION MODELER - LEVEL 4	[redacted]	1	$ [redacted]										
107	IT SYSTEMS ENGINEER - LEVEL 4	[redacted]	1	$ [redacted]										
108	LEVEL 3	[redacted]	1	$ [redacted]										
109	IT SYSTEMS ENGINEER - LEVEL 4	[redacted]	1	$ [redacted]										
110	LEVEL 3	[redacted]	1	$ [redacted]										
111	IT COMPUTER OPERATORS - LEVEL 3 (SW)	[redacted]	1	$ [redacted]										
112	IT SUPPORT CENTER CONSULTANT - LEVEL 3	[redacted]	1	$ [redacted]										
113	IT SYSTEMS ENGINEER - LEVEL 4	[redacted]	1	$ [redacted]										
114	IT COMPUTER OPERATORS - LEVEL 3 (SW)	[redacted]	1	$ [redacted]										
115	IT SYSTEMS ENGINEER - LEVEL 4	[redacted]	1	$ [redacted]										
116	LEVEL 4	[redacted]	1	$ [redacted]										
117	LEVEL 4	[redacted]	1	$ [redacted]										
118	IT SUPERVISOR-APPLICATION DEVELOPMENT	[redacted]	1	$ [redacted]										
119	LEVEL 3	[redacted]	1	$ [redacted]										
120	LEVEL 4	[redacted]	1	$ [redacted]										
121	IT SUPPORT CENTER CONSULTANT - LEVEL 3	[redacted]	1	$ [redacted]										
122	3	[redacted]	1	$ [redacted]										
123	4	[redacted]	1	$ [redacted]										
124	IT COMPUTER OPERATORS - LEVEL 3 (SW)	[redacted]	1	$ [redacted]										
125	LEVEL 3	[redacted]	1	$ [redacted]										
126	IT TECHNICIAN-LEVEL 4	[redacted]	1	$ [redacted]										
127	IT SYSTEMS ENGINEER - LEVEL 4	[redacted]	1	$ [redacted]										
128	4	[redacted]	1	$ [redacted]										
129	IT SYSTEMS ENGINEER - LEVEL 4	[redacted]	1	$ [redacted]										
130	IT COMPUTER OPERATORS - LEVEL 3 (SW)	[redacted]	1	$ [redacted]										
131	IT SUPPORT CENTER CONSULTANT - LEVEL 3	[redacted]	1	$ [redacted]										
132	3	[redacted]	1	$ [redacted]										
133	IT DATABASE ADMINISTRATOR - LEVEL 4	[redacted]	1	$ [redacted]										
134	IT COMPUTER OPERATOR - LEVEL 4	[redacted]	1	$ [redacted]										
135	LEVEL 4	[redacted]	1	$ [redacted]										
136	IT SYSTEMS ENGINEER - LEVEL 4	[redacted]	1	$ [redacted]										
137	IT SYSTEMS ENGINEER - LEVEL 4	[redacted]	1	$ [redacted]										
138	IT SYSTEMS ENGINEER - LEVEL 3	[redacted]	1	$ [redacted]										
139	IT SYSTEMS ENGINEER - LEVEL 3	[redacted]	1	$ [redacted]										
140	IT COMPUTER OPERATOR - LEVEL 4	[redacted]	1	$ [redacted]										
141	IT BUSINESS SOLUTIONS ANALYST-LEVEL 3	[redacted]	1	$ [redacted]										
142	IT BUSINESS SOLUTIONS ANALYST-LEVEL 4	[redacted]	1	$ [redacted]										
143	IT TECHNICIAN-LEVEL 4	[redacted]	1	$ [redacted]										
144	LEVEL 4	[redacted]	1	$ [redacted]										

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PUBLIC VERSION
PROTECTED MATERIALS REDACTED

NUSCO*
Information Systems Savings Exhibit
January 1, 2014 to December 31, 2014 Merger Reductions

Line	Title	1/1/14 Company Col. A	Head count Col. B	Salary Col. C	Year End Date Col. D	Days in year after Term Date Col. E	2014 Current Year Labor Savings: 2014 Salary Savings Col. F	Benefits Loader Col. G	Benefits Savings Col. H	Payroll Tax Loader Col. I	Payroll Tax Savings	Adjusted PR Tax Savings Col. J	Pension & PBOP Savings Col. K	Total Savings L=F+H+J+K
145	LEVEL 3	[redacted]	1	$ [redacted]										
146	IT COMPUTER SECURITY TECHNICIAN - LEVEL 1	[redacted]	1	$ [redacted]										
147	IT DATABASE ADMINISTRATOR - LEVEL 4	[redacted]	1	$ [redacted]										
148	IT MANAGER - APPLICATION DEVELOPMENT	[redacted]	1	$ [redacted]										
149	IT BUSINESS SOLUTIONS ANALYST-LEVEL 3	[redacted]	1	$ [redacted]										
150	IT SYSTEMS ENGINEER - LEVEL 3	[redacted]	1	$ [redacted]										
151	IT SYSTEMS ENGINEER - LEVEL 4	[redacted]	1	$ [redacted]										
152	IT SUPERVISOR-STORAGE	[redacted]	1	$ [redacted]										
153	IT SYSTEMS ENGINEER - LEVEL 3	[redacted]	1	$ [redacted]										
154		**Total**	153	$ 15,350,918			$ 9,240,836		$ 3,149,116		$ 743,653	$ 743,653	$ 1,301,515	$ 14,435,120

*On July 1, 2015, Northeast Utilities Service Company's (NUSCO) legal name was changed to Eversource Energy Service Company.

NUSCO*
Information Systems Savings Exhibit
January 1, 2014 to December 31, 2014 Merger Reductions

							2015 Annualized Labor Savings								
Line	Title	1/1/14 Company Col. A	Head count Col. B	Salary Col. C	Year End Date Col. D	Days in year after Term Date Col. E	2014 Salary Savings Col. M	Benefit Loader Col. N	Benefit Savings Col. O	Payroll Tax Loader Col. P	Payroll Tax Savings	Remove excess FICA in PR Tax Savings	Adjusted Tax Savings Col. Q	Pension & PBOP Savings Col. R	Total Savings S=M+O+Q+R
1	IT Systems Engineer-Level 3	[redacted]	1	$ [redacted]											
2	Senior Planning Analyst		1	$											
3	IT Bus App Sys Developer-Lvl 3		1	$											
4	IT Bus App Sys Developer-Lvl 4		1	$											
5	IT Project Manager-Level 3		1	$											
6	IT Supervisor-Appl Development		1	$											
7	IT Bus App Sys Developer-Lvl 4		1	$											
8	IT Database Administratr-Lvl 4		1	$											
9	IT Systems Engineer-Level 4		1	$											
10	IT Supervisor, X86		1	$											
11	IT Bus App Sys Developer-Lvl 4		1	$											
12	IT Bus App Sys Developer-Lvl 4		1	$											
13	IT Systems Engineer-Level 3		1	$											
14	IT Supervisor-Appl Development		1	$											
15	IT Systems Engineer-Level 4		1	$											
16	IT Bus App Sys Developer-Lvl 4		1	$											
17	Solutions Architect		1	$											
18	IT Supervisor, UNIX		1	$											
19	IT Database Administratr-Lvl 4		1	$											
20	IT Supervisor-Appl Development		1	$											
21	IT SYSTEMS ENGINEER - LEVEL 3		1	$											
22	LEVEL 2		1	$											
23	IT SYSTEMS ENGINEER - LEVEL 4		1	$											
24	IT VOICE COMMUNICATIONS ANALYST - LEVEL 3		1	$											
25	LEVEL 4		1	$											
26	LEVEL 1		1	$											
27	SCADA / EMS TECHNOLOGY SUPPORT COORDINATOR		1	$											
28	QUALITY ASSURANCE SPECIALIST		1	$											
29	IT BUSINESS SOLUTIONS ANALYST-LEVEL 4		1	$											
30	LEVEL 3		1	$											
31	IT WEBMASTER - LEVEL 3		1	$											
32	IT PROJECT COORDINATOR - LEVEL 4		1	$											
33	IT TECHNICIAN-LEVEL 2		1	$											
34	IT CONSULTANT-LEVEL 1		1	$											
35	IT SYSTEMS ENGINEER - LEVEL 2		1	$											
36	LEVEL 3		1	$											
37	LEVEL 1		1	$											
38	LEVEL 4		1	$											
39	LEVEL 3		1	$											
40	LEVEL 4		1	$											
41	IT SYSTEMS ENGINEER - LEVEL 4		1	$											
42	IT WEBMASTER - LEVEL 3		1	$											
43	IT Net Analyst -LAN/WAN-Level 4		1	$											
44	IT TECHNOLOGY MANAGER		1	$											

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NUSCO*
Information Systems Savings Exhibit
January 1, 2014 to December 31, 2014 Merger Reductions

							2015 Annualized Labor Savings								
Line	Title	1/1/14 Company Col. A	Head count Col. B	Salary Col. C	Year End Date Col. D	Days in year after Term Date Col. E	2014 Salary Savings Col. M	Benefit Loader Col. N	Benefit Savings Col. O	Payroll Tax Loader Col. P	Payroll Tax Savings	Remove excess FICA in PR Tax Savings	Adjusted Tax Savings Col. Q	Pension & PBOP Savings Col. R	Total Savings S=M+O+Q+R
45	IT SYSTEMS ENGINEER - LEVEL 4	[redacted]	1	$ [redacted]											
46	LEVEL 3	[redacted]	1	$ [redacted]											
47	IT PROJECT MANAGER - LEVEL 2	[redacted]	1	$ [redacted]											
48	IT DATABASE ADMINISTRATOR - LEVEL 4	[redacted]	1	$ [redacted]											
49	LEVEL 4	[redacted]	1	$ [redacted]											
50	IT DATABASE ADMINISTRATOR - LEVEL 3	[redacted]	1	$ [redacted]											
51	IT CONSULTANT-LEVEL 1	[redacted]	1	$ [redacted]											
52	3	[redacted]	1	$ [redacted]											
53	IT SYSTEMS ENGINEER - LEVEL 4	[redacted]	1	$ [redacted]											
54	LEVEL 3	[redacted]	1	$ [redacted]											
55	LEVEL 3	[redacted]	1	$ [redacted]											
56	LEVEL 4	[redacted]	1	$ [redacted]											
57	LEVEL 3	[redacted]	1	$ [redacted]											
58	IT SYSTEMS ENGINEER - LEVEL 4	[redacted]	1	$ [redacted]											
59	IT SYSTEMS ENGINEER - LEVEL 3	[redacted]	1	$ [redacted]											
60	IT CLIENT SERVICES REPRESENTATIVE - LEVEL 4	[redacted]	1	$ [redacted]											
61	LEVEL 4	[redacted]	1	$ [redacted]											
62	LEVEL 3	[redacted]	1	$ [redacted]											
63	LEVEL 4	[redacted]	1	$ [redacted]											
64	LEVEL 3	[redacted]	1	$ [redacted]											
65	LEVEL 3	[redacted]	1	$ [redacted]											
66	IT SYSTEMS ENGINEER - LEVEL 4	[redacted]	1	$ [redacted]											
67	IT SYSTEMS ENGINEER - LEVEL 4	[redacted]	1	$ [redacted]											
68	IT CLIENT SERVICES REPRESENTATIVE - LEVEL 3	[redacted]	1	$ [redacted]											
69	LEVEL 3	[redacted]	1	$ [redacted]											
70	IT TECHNICIAN-LEVEL 3	[redacted]	1	$ [redacted]											
71	LEVEL 4	[redacted]	1	$ [redacted]											
72	LEVEL 3	[redacted]	1	$ [redacted]											
73	IT SYSTEMS ENGINEER - LEVEL 4	[redacted]	1	$ [redacted]											
74	LEVEL 3	[redacted]	1	$ [redacted]											
75	LEVEL 3	[redacted]	1	$ [redacted]											
76	IT COMPUTER OPERATORS - LEVEL 3 (SW)	[redacted]	1	$ [redacted]											
77	3	[redacted]	1	$ [redacted]											
78	IT SYSTEMS ENGINEER - LEVEL 3	[redacted]	1	$ [redacted]											
79	LEVEL 3	[redacted]	1	$ [redacted]											
80	LEVEL 3	[redacted]	1	$ [redacted]											
81	LEVEL 4	[redacted]	1	$ [redacted]											
82	IT TECHNOLOGY MANAGER	[redacted]	1	$ [redacted]											
83	IT TECHNOLOGY MANAGER	[redacted]	1	$ [redacted]											
84	IT PRODUCT MANAGER LEVEL 3	[redacted]	1	$ [redacted]											
85	IT PROCESS ANALYST-LEVEL 3	[redacted]	1	$ [redacted]											
86	IT VOICE COMMUNICATIONS ANALYST - LEVEL 3	[redacted]	1	$ [redacted]											
87	IT SUPPORT CENTER CONSULTANT - LEVEL 3	[redacted]	1	$ [redacted]											
88	IT SYSTEMS ENGINEER - LEVEL 4	[redacted]	1	$ [redacted]											
89	IT SYSTEMS ENGINEER - LEVEL 4	[redacted]	1	$ [redacted]											

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PUBLIC VERSION
PROTECTED MATERIALS REDACTED

NUSCO*
Information Systems Savings Exhibit
January 1, 2014 to December 31, 2014 Merger Reductions

							2015 Annualized Labor Savings								
Line	Title	1/1/14 Company Col. A	Head count Col. B	Salary Col. C	Year End Date Col. D	Days in year after Term Date Col. E	2014 Salary Savings Col. M	Benefit Loader Col. N	Benefit Savings Col. O	Payroll Tax Loader Col. P	Payroll Tax Savings	Remove excess FICA in PR Tax Savings	Adjusted Tax Savings Col. Q	Pension & PBOP Savings Col. R	Total Savings S=M+O+Q+R
90	IT SYSTEMS ENGINEER - LEVEL 3	[redacted]	1	$ [redacted]											
91	IT DATABASE ADMINISTRATOR - LEVEL 4	[redacted]	1	$ [redacted]											
92	IT SYSTEMS ENGINEER - LEVEL 3	[redacted]	1	$ [redacted]											
93	LEVEL 3	[redacted]	1	$ [redacted]											
94	IT SYSTEMS ENGINEER - LEVEL 4	[redacted]	1	$ [redacted]											
95	IT SUPERVISOR, COMPUTER OPERATIONS	[redacted]	1	$ [redacted]											
96	IT CONSULTANT	[redacted]	1	$ [redacted]											
97	IT SYSTEMS ENGINEER - LEVEL 3	[redacted]	1	$ [redacted]											
98	LEVEL 4	[redacted]	1	$ [redacted]											
99	IT SECURITY ENGINEER LEVEL 4	[redacted]	1	$ [redacted]											
100	LEVEL 3	[redacted]	1	$ [redacted]											
101	LEVEL 4	[redacted]	1	$ [redacted]											
102	LEVEL 4	[redacted]	1	$ [redacted]											
103	IT NETWORK SYSTEMS ENGINEER - LEVEL 4	[redacted]	1	$ [redacted]											
104	LEVEL 3	[redacted]	1	$ [redacted]											
105	LEVEL 4	[redacted]	1	$ [redacted]											
106	IT INFORMATION MODELER - LEVEL 4	[redacted]	1	$ [redacted]											
107	IT SYSTEMS ENGINEER - LEVEL 4	[redacted]	1	$ [redacted]											
108	LEVEL 3	[redacted]	1	$ [redacted]											
109	IT SYSTEMS ENGINEER - LEVEL 4	[redacted]	1	$ [redacted]											
110	LEVEL 3	[redacted]	1	$ [redacted]											
111	IT COMPUTER OPERATORS - LEVEL 3 (SW)	[redacted]	1	$ [redacted]											
112	IT SUPPORT CENTER CONSULTANT - LEVEL 3	[redacted]	1	$ [redacted]											
113	IT SYSTEMS ENGINEER - LEVEL 4	[redacted]	1	$ [redacted]											
114	IT COMPUTER OPERATORS - LEVEL 3 (SW)	[redacted]	1	$ [redacted]											
115	IT SYSTEMS ENGINEER - LEVEL 4	[redacted]	1	$ [redacted]											
116	LEVEL 4	[redacted]	1	$ [redacted]											
117	LEVEL 4	[redacted]	1	$ [redacted]											
118	IT SUPERVISOR-APPLICATION DEVELOPMENT	[redacted]	1	$ [redacted]											
119	LEVEL 3	[redacted]	1	$ [redacted]											
120	LEVEL 4	[redacted]	1	$ [redacted]											
121	IT SUPPORT CENTER CONSULTANT - LEVEL 3	[redacted]	1	$ [redacted]											
122	3	[redacted]	1	$ [redacted]											
123	4	[redacted]	1	$ [redacted]											
124	IT COMPUTER OPERATORS - LEVEL 3 (SW)	[redacted]	1	$ [redacted]											
125	LEVEL 3	[redacted]	1	$ [redacted]											
126	IT TECHNICIAN-LEVEL 4	[redacted]	1	$ [redacted]											
127	IT SYSTEMS ENGINEER - LEVEL 4	[redacted]	1	$ [redacted]											
128	4	[redacted]	1	$ [redacted]											
129	IT SYSTEMS ENGINEER - LEVEL 4	[redacted]	1	$ [redacted]											
130	IT COMPUTER OPERATORS - LEVEL 3 (SW)	[redacted]	1	$ [redacted]											
131	IT SUPPORT CENTER CONSULTANT - LEVEL 3	[redacted]	1	$ [redacted]											
132	3	[redacted]	1	$ [redacted]											
133	IT DATABASE ADMINISTRATOR - LEVEL 4	[redacted]	1	$ [redacted]											
134	IT COMPUTER OPERATOR - LEVEL 4	[redacted]	1	$ [redacted]											

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PUBLIC VERSION
PROTECTED MATERIALS REDACTED

NUSCO*
Information Systems Savings Exhibit
January 1, 2014 to December 31, 2014 Merger Reductions

							2015 Annualized Labor Savings								
Line	Title	1/1/14 Company Col. A	Head count Col. B	Salary Col. C	Year End Date Col. D	Days in year after Term Date Col. E	2014 Salary Savings Col. M	Benefit Loader Col. N	Benefit Savings Col. O	Payroll Tax Loader Col. P	Payroll Tax Savings	Remove excess FICA in PR Tax Savings	Adjusted Tax Savings Col. Q	Pension & PBOP Savings Col. R	Total Savings S=M+O+Q+R
135	LEVEL 4	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
136	IT SYSTEMS ENGINEER - LEVEL 4	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
137	IT SYSTEMS ENGINEER - LEVEL 4	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
138	IT SYSTEMS ENGINEER - LEVEL 3	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
139	IT SYSTEMS ENGINEER - LEVEL 3	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
140	IT COMPUTER OPERATOR - LEVEL 4	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
141	IT BUSINESS SOLUTIONS ANALYST-LEVEL 3	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
142	IT BUSINESS SOLUTIONS ANALYST-LEVEL 4	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
143	IT TECHNICIAN-LEVEL 4	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
144	LEVEL 4	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
145	LEVEL 3	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
146	IT COMPUTER SECURITY TECHNICIAN - LEVEL 1	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
147	IT DATABASE ADMINISTRATOR - LEVEL 4	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
148	IT MANAGER - APPLICATION DEVELOPMENT	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
149	IT BUSINESS SOLUTIONS ANALYST-LEVEL 3	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
150	IT SYSTEMS ENGINEER - LEVEL 3	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
151	IT SYSTEMS ENGINEER - LEVEL 4	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
152	IT SUPERVISOR-STORAGE	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
153	IT SYSTEMS ENGINEER - LEVEL 3	[redacted]	1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
154		**Total**	153	$ 15,350,918			$ 15,350,918		$ 5,210,376		$ 1,235,284	$ (23,184)	$ 1,212,100	$ 2,130,792	$ 23,904,186

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NUSCO*
Information Systems Savings Exhibit
January 1, 2014 to December 31, 2014 Merger Attrition

Line	(A) Job Title	(B) 1/1/14 Company	(C) Employees
1	IT BUSINESS APPLICATION SYSTEMS DEVELOPER- LEVEL 1	[redacted]	1
2	IT SYSTEMS ENGINEER - LEVEL 3		1
3	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3		1
4	IT SYSTEMS ENGINEER - LEVEL 2		1
5	IT COMPUTER OPERATORS - LEVEL 3 (SW)		1
6	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3		1
7	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3		1
8	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3		1
9	IT TELECOMMUNICATIONS ENGINEER - LEVEL 2		1
10	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3		1
11	IT BUSINESS SOLUTIONS ANALYST-LEVEL 2		1
12	IT PROJECT MANAGER - LEVEL 1		1
13	IT BUSINESS SOLUTIONS ANALYST-LEVEL 4		1
14	ENTERPRISE ARCHITECT		1
15	IT SECURITY ENGINEER LEVEL 2		1
16	IT Bus App Sys Developer-Lvl 4		1
17	IT Bus App Sys Developer-Lvl 3		1
18	IT Systems Engineer-Level 4		1
19	IT Bus App Sys Developer-Lvl 4		1
20		**Exits 1/1/14 to 12/31/14:**	**-19**

Line	(A) Job Title	(B) 1/1/14 Company	(C) Employees
21	IT TELECOMMUNICATIONS ENGINEER - LEVEL 3	[redacted]	1
22	IT BUSINESS SOLUTIONS ANALYST-LEVEL 4		1
23	IT BUSINESS SOLUTIONS ANALYST-LEVEL 4		1
24	ENTERPRISE ARCHITECT		1
25	IT SYSTEMS ENGINEER - LEVEL 4		1
26	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 4		1
27	Solutions Architect		1
28		**Hires 1/1/14 to 12/31/14:**	**7**
29		**Net Attrition:**	**-12**

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Merger-related attrition is the difference between the number of employee exits and the number of new hires for employees who performed shared services functions on a year-by-year basis.

PUBLIC VERSION
PROTECTED MATERIALS REDACTED

NUSCO*
Information Systems Savings Exhibit
January 1, 2015 to September 30, 2015 Merger Reductions

Line	Job Title	1/1/14 Company Col. A	Head count Col. B	Salary Col. C	Year End Date Col. D	Days in year after Term Date Col. E	2015 Current Year Labor Savings: 2015 Salary Savings Col. F	Benefits Loader Col. G	Benefits Savings Col. H	Payroll Tax Loader Col. I	Payroll Tax Savings	Remove excess FICA in PR Tax Savings	Adjusted PR Tax Savings Col. J	Pension & PBOP Savings Col. K	Total Savings L=F+H+J+K
1	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3	[redacted]	1	$ [redacted]											
2	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 4	[redacted]	1	$ [redacted]											
3	IT DATABASE ADMINISTRATOR - LEVEL 4	[redacted]	1	$ [redacted]											
4	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 4	[redacted]	1	$ [redacted]											
5	IT CONSULTANT-LEVEL 1	[redacted]	1	$ [redacted]											
6	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3	[redacted]	1	$ [redacted]											
7	IT CONSULTANT-LEVEL 1	[redacted]	1	$ [redacted]											
8	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 4	[redacted]	1	$ [redacted]											
9	IT SYSTEMS ENGINEER-OPERATIONS - LEVEL 3	[redacted]	1	$ [redacted]											
10	IT TECHNOLOGY MANAGER	[redacted]	1	$ [redacted]											
11	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 4	[redacted]	1	$ [redacted]											
12	IT PROJECT MANAGER - LEVEL 3	[redacted]	1	$ [redacted]											
13	IT Net Analyst-LAN/WAN-Level 4	[redacted]	1	$ [redacted]											
14		Total	13	$ 1,514,420			$ 1,481,989		$ 312,591		$ 136,343	$ (3,626)	$ 132,717	$ 204,029	$ 2,131,326

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NUSCO*
Information Systems Savings Exhibit
January 1, 2015 to September 30, 2015 Merger Reductions

							2015 Annualized Labor Savings								
Line	**Job Title**	**1/1/14 Company Col. A**	**Head count Col. B**	**Salary Col. C**	**Year End Date Col. D**	**Days in year after Term Date Col. E**	**2015 Salary Savings Col. M**	**Benefit Loader Col. N**	**Benefit Savings Col. O**	**Payroll Tax Loader Col. P**	**Payroll Tax Savings**	**Remove excess FICA in PR Tax Savings**	**Adjusted Tax Savings Col. Q**	**Pension & PBOP Savings Col. R**	**Total Savings S=M+O+Q+R**
1	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3	[redacted]	1	$ [redacted]											
2	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 4	[redacted]	1	$ [redacted]											
3	IT DATABASE ADMINISTRATOR - LEVEL 4	[redacted]	1	$ [redacted]											
4	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 4	[redacted]	1	$ [redacted]											
5	IT CONSULTANT-LEVEL 1	[redacted]	1	$ [redacted]											
6	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3	[redacted]	1	$ [redacted]											
7	IT CONSULTANT-LEVEL 1	[redacted]	1	$ [redacted]											
8	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 4	[redacted]	1	$ [redacted]											
9	IT SYSTEMS ENGINEER-OPERATIONS - LEVEL 3	[redacted]	1	$ [redacted]											
10	IT TECHNOLOGY MANAGER	[redacted]	1	$ [redacted]											
11	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 4	[redacted]	1	$ [redacted]											
12	IT PROJECT MANAGER - LEVEL 3	[redacted]	1	$ [redacted]											
13	IT Net Analyst-LAN/WAN-Level 4	[redacted]	1	$ [redacted]											
14		Total	13	$ 1,514,420			$ 1,514,420		$ 319,431		$ 139,327	$ (4,681)	$ 134,646	$ 207,884	$ 2,176,381

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NUSCO*
Information Systems Savings Exhibit
January 1, 2015 to September 30, 2015 Merger Attrition

Line	(A) Job Title	(B) 1/1/14 Company	(C) Employees
1	Enterprise Architect	[redacted]	1
2	IT Bus App Sys Developer-Lvl 4		1
3	IT Business Solutions Analyst-Level 4		1
4	IT Information Modeler - Level 4		1
5	Telecommunications Coordinator		1
6	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 4		1
7	IT NETWORK ANALYST - LAN/WAN - LEVEL 4		1
8	IT SUPERVISOR-SECURITY OPERATIONS		1
9		**Exits 1/1/15 to 9/30/15:**	**-8**

Line	(A) Job Title	(B) 1/1/14 Company	(C) Employees
10	IT SECURITY ENGINEER LEVEL 2	[redacted]	1
11	IT Analyst, Network LAN/WAN Level 3		1
12	IT Analyst, Network LAN/WAN Level 3		1
13		**Hires 1/1/15 to 9/30/15:**	**3**
14		**Net Attrition:**	**-5**

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Merger-related attrition is the difference between the number of employee exits and the number of new hires for employees who performed shared services functions on a year-by-year basis.

Exhibit No. ES-107

Insurance Savings Exhibit

Eversource Energy Service Company

Eversource Energy Services Company
Insurance Savings Exhibit

	Savings				
(A)	(B) 2012	(C) 2013	(D) 2014	(E) 2015	(F) Total
1 Savings	$ 1,494,184 (a)	$ 2,164,088 (b)	$ 2,164,088	$ 2,196,766	
2 Inflation Rate (c)			1.51%	1.06%	
3 Total Insurance Savings ((Ln 1 * Ln 2) + Ln 1)	$ 1,494,184 (d)	$ 2,164,088 (d)	$ 2,196,766 (d)	$ 1,665,039 (e)	$ 7,520,076

(G) Allocation to Transmission:	(H) Allocation %	(I)= (B), Ln 3 *(H) 2012	(J)= (C), Ln 3 *(H) 2013	(K)= (D), Ln 3 *(H) 2014	(L)= (E), Ln 3 *(H) 2015	(M) = (I) + (J) + (K) + (L) Total
4 CL&P	15.93% (f)	$ 238,023	$ 344,739	$ 349,945	$ 265,241	$ 1,197,948
5 NSTAR Electric	11.06% (f)	$ 165,257	$ 239,348	$ 242,962	$ 184,153	$ 831,720
6 PSNH	3.59% (f)	$ 53,641	$ 77,691	$ 78,864	$ 59,775	$ 269,971
7 WMECO	4.54% (f)	$ 67,836	$ 98,250	$ 99,733	$ 75,593	$ 341,411
8 **Total Transmission (Sum Ln 4- Ln 7)**	35.12%	$ 524,757	$ 760,028	$ 771,504	$ 584,762	$ 2,641,051

(a) Exhibit No. ES-107, Page 2, Line 18 (B)
(b) Exhibit No. ES-107, Page 2, Line 18 (C)
(c) Source of Inflation Rate is the quarterly, seasonally adjusted change in the Gross Domestic Product Implicit Price Deflator based on an index year of 2009 (2009 = 100) obtained from the Bureau of Labor Statistics. Calculation of the annual inflation rate can be found in Exhibit No. ES-115
(d) Exhibit No. ES-103, Page 4, Line 5
(e) Annual savings multiplied by .75 to prorate and only include savings through September 30, 2015.
(f) Source is Exhibit No. ES-116

Eversource Energy Services Company
Insurance Savings Exhibit

	(A) Vendor	Savings (Costs) (B) 2012		Savings (Costs) (C) 2013	
1	[redacted]	$ 65,235		$ 260,940	
2		$ (9,566)		$ (22,959)	
3		$ (2,255)		$ (3,007)	
4		$ 91,935		$ 137,903	
5		$ -		$ -	
6		$ 827		$ 1,102	
7		$ 564,817		$ 847,226	
8		$ 807,926		$ 1,077,235	
9		$ 30,272		$ 40,362	
10		$ (10,000)		$ (120,000)	
11		$ (8,207)		$ (14,069)	
12		$ -		$ -	
13		$ 1,292		$ 1,292	
14		$ (29,819)		$ (29,819)	
15		$ (9,631)		$ (14,446)	
16		$ -		$ -	
17		$ 1,358		$ 2,328	
18	**Total Savings (Sum Ln 1- Ln 17)**	$ 1,494,184	(a)	$ 2,164,088	(b)

(a) Exhibit No. ES-107, Page 3, Line 18 (H)
(b) Exhibit No. ES-107, Page 3, Line 18 (I)

Eversource Energy Services Company
Insurance Savings Exhibit

		Expenses						Savings (Costs)	
	(A)	**(B)**	**(C)**	**(D)= (B) + (C)**	**(E)**	**(F)= (D) - (E)**	**(G)**	**(H)=(F/12)*(G)**	**(I)= (D) - (E)**
	Vendor	Legacy NU Annual Premium	Legacy NSTAR Annual Premium	Total Annual Premium	Combined Eversource Annual Premium	**2012**	**# of Months New Policy in Effect**	**2012** (a)	**2013**
1	[redacted]	$ 3,455,661	$ 855,279	$ 4,310,940	$ 4,050,000	$ 260,940	3	$ 65,235	$ 260,940
2		$ 232,642	$ -	$ 232,642	$ 255,601	$ (22,959)	5	$ (9,566)	$ (22,959)
3		$ 45,745	$ -	$ 45,745	$ 48,752	$ (3,007)	9	$ (2,255)	$ (3,007)
4		$ 1,267,457	$ -	$ 1,267,457	$ 1,129,554	$ 137,903	8	$ 91,935	$ 137,903
5		$ -	$ 6,804	$ 6,804	$ 6,804	$ -	3	$ -	$ -
6		$ 57,926	$ 33,065	$ 90,991	$ 89,889	$ 1,102	9	$ 827	$ 1,102
7		$ 2,042,962	$ 999,339	$ 3,042,301	$ 2,195,075	$ 847,226	8	$ 564,817	$ 847,226
8		$ 4,554,837	$ 4,378,671	$ 8,933,508	$ 7,856,273	$ 1,077,235	9	$ 807,926	$ 1,077,235
9		$ 699,863	$ 212,569	$ 912,432	$ 872,070	$ 40,362	9	$ 30,272	$ 40,362
10		$ 251,512	$ -	$ 251,512	$ 371,512	$ (120,000)	1	$ (10,000)	$ (120,000)
11		$ 83,571	$ 51,135	$ 134,706	$ 148,775	$ (14,069)	7	$ (8,207)	$ (14,069)
12		$ 7,489	$ -	$ 7,489	$ 7,489	$ -	3	$ -	$ -
13		$ 4,167	$ 1,708	$ 5,875	$ 4,583	$ 1,292	12	$ 1,292	$ 1,292
14		$ 667,550	$ -	$ 667,550	$ 697,369	$ (29,819)	12	$ (29,819)	$ (29,819)
15		$ 199,816	$ -	$ 199,816	$ 214,262	$ (14,446)	8	$ (9,631)	$ (14,446)
16		$ -	$ 730,310	$ 730,310	$ 730,310	$ -	3	$ -	$ -
17		$ 7,776		$ 7,776	$ 5,448	$ 2,328	7	$ 1,358	$ 2,328
18	**Total (Sum Ln 1- Ln 17)**	$ 13,578,974	$ 7,268,880	$ 20,847,854	$ 18,683,766	$ 2,164,088		$ 1,494,184	$ 2,164,088

(a) 2012 Savings are calculated as the total annual premium prior to merger (D), minus the combined Eversource annual premium after the merger (E), divided by 12, multiplied by the total number of month savings (G) for each contract in 2012.

Exhibit No. ES-108

Professional Services Savings Exhibit

Eversource Energy Service Company

Eversource Energy Service Company
Professional Services Savings Exhibit

	(A)	Savings (B) 2012		(C) 2013		(D) 2014		(E) 2015		(F) Total
1	Savings	$ 819,087	(a)	$ 1,263,774	(b)	$ 1,263,774		$ 1,282,857		
2	Inflation Rate (c)					1.51%		1.06%		
3	Total Professional Services Savings ((Ln 1 * Ln 2) + Ln 1)	$ 819,087	(d)	$ 1,263,774	(d)	$ 1,282,857	(d)	$ 972,341	(e)	$ 4,338,059

	(G) Allocation to Transmission:	(H) Allocation %		(I)= (B), Ln 3 *(H) 2012	(J)= (C), Ln 3 *(H) 2013	(K)= (D), Ln 3 *(H) 2014	(L)= (E), Ln 3 *(H) 2015	(M)= (I) + (J) + (K) + (L) Total
4	CL&P	15.93%	(f)	$ 130,481	$ 201,319	$ 204,359	$ 154,894	$ 691,053
5	NSTAR Electric	11.06%	(f)	$ 90,591	$ 139,773	$ 141,884	$ 107,541	$ 479,789
6	PSNH	3.59%	(f)	$ 29,405	$ 45,369	$ 46,055	$ 34,907	$ 155,736
7	WMECO	4.54%	(f)	$ 37,187	$ 57,375	$ 58,242	$ 44,144	$ 196,948
8	**Total Transmission (Sum Ln 4- Ln 7)**	35.12%		$ 287,663	$ 443,837	$ 450,539	$ 341,486	$ 1,523,526

(a) Exhibit No. ES-108, Page 2, Line 9 (B)
(b) Exhibit No. ES-108, Page 2, Line 9 (C)
(c) Source of Inflation Rate is the quarterly, seasonally adjusted change in the Gross Domestic Product Implicit Price Deflator based on an index year of 2009 (2009 = 100) obtained from the Bureau of Labor Statistics. Calculation of the annual inflation rate can be found in Exhibit No. ES-115.
(d) Exhibit No. ES-103, Page 4, Line 7
(e) Annual savings multiplied by .75 to prorate and only include savings through September 30, 2015
(f) Source is Exhibit No. ES-116

Eversource Energy Service Company
Professional Services Savings Exhibit

		Savings (Costs)			
	(A)	(B)		(C)	
	Vendor	2012		2013	
1	[redacted]	$ (890,000)		$ (730,000)	
2		$ 20,600		$ 61,800	
3		$ 95,000		$ 130,000	
4		$ 1,500,000		$ 1,500,000	
5		$ 60,799		$ 121,598	
6		$ -		$ 15,000	
7		$ 32,688		$ 65,376	
8		$ -		$ 100,000	
9	**Total Savings (Sum Ln 1- Ln 8)**	$ 819,087	(a)	$ 1,263,774	(b)

(a) Exhibit No. ES-108, Page 3, Line 9 (E)
(b) Exhibit No. ES-108, Page 3, Line 9 (F)

Eversource Energy Service Company
Professional Services Savings Exhibit

		Expenses			Savings (Costs)	
	(A)	(B)	(C)	(D)	(E) = (B) - (C)	(F) = (B) - (D)
	Vendor	2011	2012	2013	2012	2013
1	[redacted]	$ 2,500,000	$ 3,390,000	$ 3,230,000	$ (890,000)	$ (730,000)
2		$ 61,800	$ 41,200	$ -	$ 20,600	$ 61,800
3		$ -	$ (95,000)	$ (130,000)	$ 95,000	$ 130,000
4		$ 1,500,000	$ -	$ -	$ 1,500,000	$ 1,500,000
5		$ 121,598	$ 60,799	$ -	$ 60,799	$ 121,598
6		$ 15,000	$ 15,000	$ -	$ -	$ 15,000
7		$ 65,376	$ 32,688	$ -	$ 32,688	$ 65,376
8		$ 100,000	$ 100,000	$ -	$ -	$ 100,000
9	**Total (Sum Ln 1- Ln 8)**	$ 4,363,774	$ 3,544,687	$ 3,100,000	$ 819,087	$ 1,263,774

Eversource worked to consolidate and reduce professional services activities (including corporate procurement credit cards (P-Card), vendors for payroll services, vendors for staff management, external auditors, research services, call center contracts, and financial reporting services) through economies of scope, elimination of non-recurring duplicate services, and increased utilization of a broader skill base. In many cases these were duplicative functions in the Legacy Companies.

(a) Rebates received from vendors as a result of consolidating corporate procurement credit cards.

Exhibit No. ES-109

Contract Services Savings Exhibit

Eversource Energy Service Company

Eversource Energy Service Company
Contract Services Savings Exhibit

	(A)	Savings (B) 2012		(C) 2013		(D) 2014		(E) 2015		(F) Total
1	Savings	$ 1,834,300	(a)	$ 7,277,547	(b)	$ 7,235,812	(c)	$ 7,235,812		
2	Inflation Rate (d)							1.06%		
3	Total Contract Services Savings ((Ln 1 * Ln 2) + Ln 1)	$ 1,834,300		$ 7,277,547		$ 7,235,812		$ 7,312,512		
4	Capitalization Rate (e)	62.77%		60.96%		61.05%		61.46%		
5	Total O&M Savings (Ln 3*(1-Ln 4))	$ 682,910		$ 2,841,454		$ 2,818,349		$ 2,818,242		
6	Total Capitalized Savings (Ln 3-Ln 5)	$ 1,151,390		$ 4,436,093		$ 4,417,463		$ 4,494,270		
7	Depreciation Rate (f)			3.32%		3.22%		3.30%		
8	Return + Depreciation Rate + Property Tax Rate (g)	17.38%		17.22%		16.48%		16.66%		
	Capitalized Savings, adjusted for Depreciation									
9	2012	$ 1,151,390		$ 1,113,186	(h)	$ 1,078,434	(i)	$ 1,041,123	(k)	
10	2013	$ -		$ 4,436,093		$ 4,293,251	(j)	$ 4,148,142	(l)	
11	2014	$ -		$ -		$ 4,417,463		$ 4,271,687	(m)	
12	2015	$ -		$ -		$ -		$ 4,494,270		
13	Total (Sum Ln 9- Ln 12)	$ 1,151,390		$ 5,549,279		$ 9,789,149		$ 13,955,221		
14	Revenue Requirements for the Capitalized Accounts (Ln 8 * Ln 13)	$ 200,149		$ 955,363		$ 1,613,252		$ 2,324,940		
15	Contract Services Savings and Revenue Requirements (Ln 5 + Ln 14)	$ 883,059		$ 3,796,817	(n)	$ 4,431,601	(n)	$ 3,857,386	(o)	$ 12,968,862

	(G) Allocation to Transmission:	(H) Allocation %		(I) = (B), Ln 15 *(H) 2012	(J)= (C), Ln 15 *(H) 2013	(K)= (D), Ln 15 *(H) 2014	(L)= (E), Ln 15 *(H) 2015	(M)= (I) + (J) + (K) + (L) Total
16	CL&P	3.10%	(p)	$ 27,375	$ 117,701	$ 137,380	$ 119,579	$ 402,035
17	NSTAR Electric	8.10%	(p)	$ 71,528	$ 307,542	$ 358,960	$ 312,448	$ 1,050,478
18	PSNH	1.00%	(p)	$ 8,831	$ 37,968	$ 44,316	$ 38,574	$ 129,689
19	WMECO	0.30%	(p)	$ 2,649	$ 11,390	$ 13,295	$ 11,572	$ 38,907
20	**Total Transmission (Sum Ln 16- Ln 19)**	12.50%		$ 110,382	$ 474,602	$ 553,950	$ 482,173	$ 1,621,108

(a) Exhibit No. ES-109, Page 3, Line 109 (B)
(b) Exhibit No. ES-109, Page 3, Line 109 (C)
(c) Exhibit No. ES-109, Page 3, Ln 109 (D)
(d) Source of Inflation Rate is the quarterly, seasonally adjusted change in the Gross Domestic Product Implicit Price Deflator based on an index year of 2009 (2009 = 100) obtained from the Bureau of Labor Statistics. Calculation of the annual inflation rate can be found in Exhibit No. ES-115.
(e) Capitalization Rate represents the portion of Contract Services costs which were included in capitalized FERC accounts in the given year based on queries of Eversource accounting database.
(f) Depreciation Rate is calculated using Depreciation Expense from FERC Form 1, p336, Ln 12 divided by Net Utility Plant from FERC Form 1, p 110, Ln 6.
(g) Return Rate calculation is consistent with method as filed in the PTO AC Annual Informational Filing; return on equity (ROE) component is based on Eversource Distribution companies allowed ROE to be consistent with the merger cost/savings report submitted for state regulatory purposes. Depreciation Rate component see (g) above. Property Tax Rate component is calculated as Property Tax Expense divided by Net Utility Plant from FERC Form 1, p 110, Ln 6.

(h) Capitalized Savings, adjusted for Depreciation is calculated as (B), Ln 6 * (1-(C), Ln 7), for number of periods since initial savings
(i) Capitalized Savings, adjusted for Depreciation is calculated as (B), Ln 6 * (1-(D), Ln 7), for number of periods since initial savings
(j) Capitalized Savings, adjusted for Depreciation is calculated as (C), Ln 6 * (1-(D), Ln 7), for number of periods since initial savings
(k) Capitalized Savings, adjusted for Depreciation is calculated as (B), Ln 6 * (1-(E), Ln 7), for number of periods since initial savings
(l) Capitalized Savings, adjusted for Depreciation is calculated as (C), Ln 6 * (1-(E), Ln 7), for number of periods since initial savings
(m) Capitalized Savings, adjusted for Depreciation is calculated as (D), Ln 6 * (1-(E), Ln 7), for number of periods since initial savings
(n) Exhibit No. ES-103, Page 4, Line 14
(o) Annual savings multiplied by .75 to prorate and only include savings through September 30, 2015.
(p) Source is Exhibit No. ES-116

Eversource Energy Service Company
Contract Services Savings Exhibit

		Savings		
	(A) Vendor	(B) 2012	(C) 2013	(D) 2014
1	[redacted]	$ -	$ -	$ 2,116
2	[redacted]	$ -	$ 321,150	$ 280,000
3	[redacted]	$ -	$ 563	$ 1,087
4	[redacted]	$ -	$ -	$ 100,000
5	[redacted]	$ -	$ 67,800	$ -
6	[redacted]	$ -	$ 136,227	$ -
7	[redacted]	$ -	$ 12,667	$ -
8	[redacted]	$ -	$ -	$ 112
9	[redacted]	$ 102,000	$ -	$ -
10	[redacted]	$ -	$ 15,000	$ 15,000
11	[redacted]	$ 50,000	$ -	$ 518,000
12	[redacted]	$ 750,000	$ -	$ -
13	[redacted]	$ -	$ -	$ 1,200,000
14	[redacted]	$ -	$ -	$ 835,247
15	[redacted]	$ -	$ -	$ 10,000
16	[redacted]	$ -	$ 39,600	$ 39,600
17	[redacted]	$ -	$ 572,070	$ -
18	[redacted]	$ -	$ 24,000	$ 24,000
19	[redacted]	$ -	$ 2,100	$ -
20	[redacted]	$ 123,000	$ 47,147	$ -
21	[redacted]	$ -	$ 75,500	$ -
22	[redacted]	$ -	$ -	$ 10,942
23	[redacted]	$ -	$ 20,850	$ -
24	[redacted]	$ -	$ 283,000	$ -
25	[redacted]	$ -	$ 3,718	$ -
26	[redacted]	$ -	$ 235,760	$ 235,760
27	[redacted]	$ -	$ -	$ 20,000
28	[redacted]	$ -	$ 1,060	$ -
29	[redacted]	$ -	$ 8,350	$ 3,750
30	[redacted]	$ -	$ 4,470	$ 4,470
31	[redacted]	$ 800	$ 108,000	$ 27,000
32	[redacted]	$ -	$ 334,510	$ 6,510
33	[redacted]	$ -	$ 120,938	$ -
34	[redacted]	$ -	$ 28,000	$ 16,000
35	[redacted]	$ -	$ 14,000	$ 37,232
36	[redacted]	$ -	$ -	$ 24,000
37	[redacted]	$ -	$ 71,590	$ 200,000
38	[redacted]	$ -	$ 3,630	$ 3,630
39	[redacted]	$ -	$ 18,000	$ -
40	[redacted]	$ -	$ 56,930	$ -
41	[redacted]	$ -	$ 816,053	$ 650,000
42	[redacted]	$ -	$ -	$ 58,000
43	[redacted]	$ -	$ 86,571	$ 86,571
44	[redacted]	$ -	$ 11,176	$ 22,352
45	[redacted]	$ -	$ 51,861	$ -
46	[redacted]	$ -	$ -	$ 2,520
47	[redacted]	$ 110,000	$ -	$ -
48	[redacted]	$ -	$ 40,000	$ 80,000
49	[redacted]	$ -	$ 3,000	$ 3,000
50	[redacted]	$ -	$ 8,540	$ 8,540
51	[redacted]	$ -	$ -	$ 58,369
52	[redacted]	$ -	$ 44,875	$ -
53	[redacted]	$ -	$ -	$ 5,400
54	[redacted]	$ -	$ 37,000	$ -
55	[redacted]	$ -	$ 19,409	$ 40,270
56	[redacted]	$ -	$ 12,000	$ -
57	[redacted]	$ -	$ 421,800	$ -
58	[redacted]	$ -	$ 8,086	$ -

Eversource Energy Service Company
Contract Services Savings Exhibit

		Savings		
	(A)	(B)	(C)	(D)
	Vendor	2012	2013	2014
59	[redacted]	$ -	$ -	$ 1,500
60	[redacted]	$ 3,000	$ -	$ -
61	[redacted]	$ -	$ 35,520	$ 32,560
62	[redacted]	$ -	$ 6,000	$ 3,000
63	[redacted]	$ -	$ 39,375	$ 39,375
64	[redacted]	$ -	$ 2,229	$ 26,745
65	[redacted]	$ -	$ 330,482	$ 315,186
66	[redacted]	$ -	$ 750,000	$ -
67	[redacted]	$ -	$ 2,536	$ -
68	[redacted]	$ -	$ 660,629	$ 666,600
69	[redacted]	$ -	$ 227,500	$ -
70	[redacted]	$ -	$ -	$ 40,000
71	[redacted]	$ -	$ -	$ 27,341
72	[redacted]	$ 300,000	$ 238,348	$ -
73	[redacted]	$ -	$ -	$ 110,000
74	[redacted]	$ -	$ 8,433	$ 101,200
75	[redacted]	$ -	$ 12,223	$ 20,953
76	[redacted]	$ -	$ 17,000	$ -
77	[redacted]	$ 38,000	$ -	$ 1,940
78	[redacted]	$ -	$ 8,925	$ -
79	[redacted]	$ -	$ -	$ 50,040
80	[redacted]	$ -	$ -	$ 30,000
81	[redacted]	$ 50,000	$ -	$ -
82	[redacted]	$ 92,000	$ -	$ -
83	[redacted]	$ -	$ -	$ 27,195
84	[redacted]	$ 3,500	$ -	$ -
85	[redacted]	$ -	$ 6,351	$ -
86	[redacted]	$ -	$ 25,000	$ 32,500
87	[redacted]	$ -	$ -	$ 4,851
88	[redacted]	$ -	$ 90,000	$ -
89	[redacted]	$ -	$ -	$ 10,000
90	[redacted]	$ -	$ -	$ 10,760
91	[redacted]	$ -	$ -	$ 11,700
92	[redacted]	$ -	$ 600	$ -
93	[redacted]	$ -	$ 15,000	$ 15,000
94	[redacted]	$ -	$ -	$ 9,000
95	[redacted]	$ 94,000	$ -	$ -
96	[redacted]	$ -	$ 61,890	$ 57,515
97	[redacted]	$ -	$ 30,000	$ 30,000
98	[redacted]	$ -	$ 9,000	$ 9,000
99	[redacted]	$ -	$ 22,500	$ -
100	[redacted]	$ -	$ 231,226	$ 231,226
101	[redacted]	$ -	$ 90,000	$ -
102	[redacted]	$ 68,000	$ -	$ -
103	[redacted]	$ -	$ 120,479	$ 126,229
104	[redacted]	$ -	$ -	$ 22,860
105	[redacted]	$ -	$ 7,500	$ 7,500
106	[redacted]	$ -	$ 1,800	$ -
107	[redacted]	$ 50,000	$ -	$ -
108	[redacted]	$ -	$ 40,000	$ 534,558
109	**Total Savings (Sum Ln 1- Ln 108)**	$ 1,834,300	$ 7,277,547	$ 7,235,812

Following the merger, Eversource consolidated the procurement contracts of Legacy NSTAR and Legacy NU by evaluating common vendors to both and renegotiating such contracts, realizing savings due to both consolidation of vendors as well as vendor concessions given to Eversource due to the merged entity s bargaining power. For many contract services, Eversource conducted a competitive bidding process that resulted in the selection of one post-merger vendor.

Exhibit No. ES-110

External Directors/Trustee Fees Savings Exhibit

Eversource Energy Service Company

Eversource Energy Service Company
External Directors/Trustee Fees Savings Exhibit

(A)		Savings (B) 2012		(C) 2013		(D) 2014		(E) 2015		(F) Total
1 Savings	$	248,776 (a)	$	1,111,849 (b)	$	1,111,849	$	1,128,638		
2 Inflation Rate (c)						1.51%		1.06%		
3 Total External Directors/Trustee Fees Savings ((Ln 1 * Ln 2) + Ln 1)	$	248,776 (d)	$	1,111,849 (d)	$	1,128,638 (d)	$	855,451 (e)	$	3,344,714

(G) Allocation to Transmission:	(H) Allocation %		(I)= (B), Ln 3 *(H) 2012		(J)= (C), Ln 3 *(H) 2013		(K)= (D), Ln 3 *(H) 2014		(L)= (E), Ln 3 *(H) 2015		(M)= (I) + (J) + (K) + (L) Total
4 CL&P	15.93% (f)	$	39,630	$	177,118	$	179,792	$	136,273	$	532,813
5 NSTAR Electric	11.06% (f)	$	27,515	$	122,970	$	124,827	$	94,613	$	369,925
6 PSNH	3.59% (f)	$	8,931	$	39,915	$	40,518	$	30,711	$	120,075
7 WMECO	4.54% (f)	$	11,294	$	50,478	$	51,240	$	38,837	$	151,850
8 Total Transmission (Sum Ln 4- Ln 7)	35.12%	$	87,370	$	390,481	$	396,378	$	300,434	$	1,174,664

(a) Exhibit No. ES-110, Page 2, Line 24 (B)
(b) Exhibit No. ES-110, Page 2, Line 24 (C)
(c) Source of Inflation Rate is the quarterly, seasonally adjusted change in the Gross Domestic Product Implicit Price Deflator based on an index year of 2009 (2009 100) obtained from the Bureau of Labor Statistics. Calculation of the annual inflation rate can be found in Exhibit No. ES-115.
(d) Exhibit No. ES-103, Page 4, Line 10
(e) Annual savings multiplied by .75 to prorate and only include savings through September 30, 2015.
(f) Source is Exhibit No. ES-116

Eversource Energy Service Company
External Directors/Trustee Fees Savings Exhibit

	(A) Trustee Name	Savings (B) 2012		Savings (C) 2013	
1	Richard H. Booth	$ 24,210		$ 43,606	
2	John S. Clarkeson	$ 31,710		$ 60,606	
3	Cotton M. Cleveland	$ 15,267		$ (23,487)	
4	Sanford Cloud, Jr.	$ (8,538)		$ 10,483	
5	James F. Cordes	$ 138,058		$ 138,058	
6	Gary L. Countryman	$ 93,000		$ 168,000	
7	E. Gail de Planque	$ 175,560		$ 175,560	
8	Thomas G. Dignan, Jr.	$ 90,750		$ 171,750	
9	James S. DiStasio	$ (45,250)		$ (51,204)	
10	Francis A. Doyle	$ (150,000)		$ (199,204)	
11	Charles K. Gifford	$ (30,000)		$ (33,954)	
12	John G. Graham	$ 73,759		$ 222,859	
13	Matina S. Horner	$ 91,450		$ 171,950	
14	Elizabeth T. Kennan	$ 122,710		$ 314,810	
15	Paul A. La Camera	$ (37,750)		$ (39,204)	
16	Kenneth R. Leibler	$ 19,210		$ 48,606	
17	Robert E. Patricelli	$ 64,710		$ 210,810	
18	Charles W. Shivery	$ (300,000)		$ (399,204)	
19	John F. Swope	$ 49,460		$ 212,810	
20	William C. Van Faasen	$ (34,000)		$ (38,954)	
21	Dennis R. Wraase	$ (32,290)		$ (9,394)	
22	Frederica M. Williams	$ (184,500)		$ (199,204)	
23	Gerald L. Wilson	$ 81,250		$ 155,750	
24	Total Savings (Sum Ln 1- Ln 23)	$ 248,776	(a)	$ 1,111,849	(b)

(a) Exhibit No. ES-110, Page 3, Line 24 (E)
(b) Exhibit No. ES-110, Page 3, Line 24 (F)

Eversource Energy Service Company
External Directors/Trustee Fees Savings Exhibit

	(A) Trustee Name	Expenses (B) 2010 (a)	Expenses (C) 2012 (b)	Expenses (D) 2013 (c)	Savings (Costs) (E) = (B) - (C) 2012	Savings (Costs) (F) = (B) - (D) 2013
1	Richard H. Booth	$ 257,810	$ 233,600	$ 214,204	$ 24,210	$ 43,606
2	John S. Clarkeson	$ 259,810	$ 228,100	$ 199,204	$ 31,710	$ 60,606
3	Cotton M. Cleveland	$ 232,867	$ 217,600	$ 256,354	$ 15,267	$ (23,487)
4	Sanford Cloud, Jr.	$ 244,687	$ 253,225	$ 234,204	$ (8,538)	$ 10,483
5	James F. Cordes	$ 138,058	$ -	$ -	$ 138,058	$ 138,058
6	Gary L. Countryman	$ 168,000	$ 75,000	$ -	$ 93,000	$ 168,000
7	E. Gail de Planque	$ 175,560	$ -	$ -	$ 175,560	$ 175,560
8	Thomas G. Dignan, Jr.	$ 171,750	$ 81,000	$ -	$ 90,750	$ 171,750
9	James S. DiStasio	$ 158,000	$ 203,250	$ 209,204	$ (45,250)	$ (51,204)
10	Francis A. Doyle	$ -	$ 150,000	$ 199,204	$ (150,000)	$ (199,204)
11	Charles K. Gifford	$ 175,250	$ 205,250	$ 209,204	$ (30,000)	$ (33,954)
12	John G. Graham	$ 222,859	$ 149,100	$ -	$ 73,759	$ 222,859
13	Matina S. Horner	$ 171,950	$ 80,500	$ -	$ 91,450	$ 171,950
14	Elizabeth T. Kennan	$ 314,810	$ 192,100	$ -	$ 122,710	$ 314,810
15	Paul A. La Camera	$ 160,000	$ 197,750	$ 199,204	$ (37,750)	$ (39,204)
16	Kenneth R. Leibler	$ 247,810	$ 228,600	$ 199,204	$ 19,210	$ 48,606
17	Robert E. Patricelli	$ 210,810	$ 146,100	$ -	$ 64,710	$ 210,810
18	Charles W. Shivery	$ -	$ 300,000	$ 399,204	$ (300,000)	$ (399,204)
19	John F. Swope	$ 212,810	$ 163,350	$ -	$ 49,460	$ 212,810
20	William C. Van Faasen	$ 160,250	$ 194,250	$ 199,204	$ (34,000)	$ (38,954)
21	Dennis R. Wraase	$ 189,810	$ 222,100	$ 199,204	$ (32,290)	$ (9,394)
22	Frederica M. Williams	$ -	$ 184,500	$ 199,204	$ (184,500)	$ (199,204)
23	Gerald L. Wilson	$ 155,750	$ 74,500	$ -	$ 81,250	$ 155,750
24	Total (Sum Ln 1- Ln 23)	$ 4,028,651	$ 3,779,875	$ 2,916,802	$ 248,776	$ 1,111,849

(a) Reflects 2010 Trustee fees paid by Northeast Utilities and reported in the Northeast Utilities proxy statement, or 2010 Trustee fees paid by NSTAR

(b) Reflects 2012 Trustee fees paid by Northeast Utilities and reported in the Northeast Utilities proxy statement, and/or 2012 Trustee fees paid by NSTAR. Upon the closing of the Northeast Utilities-NSTAR Merger, NSTAR ceased to exist and was no longer required to file a proxy statement reporting 2012 Trustee fees.

(c) Reflects 2013 Trustee fees paid by Northeast Utilities and reported in Northeast Utilities proxy statement.

Exhibit No. ES-111

Materials & Supply Procurement Savings Exhibit

Eversource Energy Service Company

Eversource Energy Service Company
Materials & Supply Procurement Savings Exhibit

		Savings				
	(A)	(B) 2012	(C) 2013	(D) 2014	(E) 2015	(F) Total
1	Savings	$ 1,497,570 (a)	$ 3,157,450 (b)	$ 10,169,501 (c)	$ 10,169,501	
2	Inflation Rate (d)				1.06%	
3	Total Material & Supply Procurement Savings ((Ln 1 * Ln 2) + Ln 1)	$ 1,497,570	$ 3,157,450	$ 10,169,501	$ 10,277,298	
4	Capitalization Rate (e)	92.02%	89.61%	89.15%	91.88%	
5	Total O&M Savings (Ln 3*(1-Ln 4))	$ 119,506	$ 328,060	$ 1,103,391	$ 834,517	
6	Total Capitalized Savings (Ln 3-Ln 5)	$ 1,378,064	$ 2,829,390	$ 9,066,110	$ 9,442,781	
7	Depreciation Rate (f)		3.32%	3.22%	3.30%	
8	Return + Depreciation Rate + Property Tax Rate (g)	17.38%	17.22%	16.48%	16.66%	
	<u>Capitalized Savings, adjusted for Depreciation</u>					
9	2012	$ 1,378,064	$ 1,332,338 (h)	$ 1,290,745 (i)	$ 1,246,088 (k)	
10	2013		$ 2,829,390	$ 2,738,284 (j)	$ 2,645,732 (l)	
11	2014			$ 9,066,110	$ 8,766,929 (m)	
12	2015				$ 9,442,781	
13	Total (Sum Ln 9- Ln 12)	$ 1,378,064	$ 4,161,728	$ 13,095,139	$ 22,101,530	
14	Revenue Requirements for the Capitalized Accounts (Ln 8 * Ln 13)	$ 239,552	$ 716,483	$ 2,158,079	$ 3,682,115	
15	Materials & Supply Savings and Revenue Requirements (Ln 5 + Ln 14)	$ 359,058 (n)	$ 1,044,542 (n)	$ 3,261,470 (n)	$ 3,387,474 (o)	$ 8,052,544

	(G) <u>Allocation to Transmission:</u>	(H) Allocation %	(I) = (B), Ln 15 *(H) 2012	(J)= (C), Ln 15 *(H) 2013	(K)= (D), Ln 15 *(H) 2014	(L)= (E), Ln 15 *(H) 2015	(M)= (I) + (J) + (K) + (L) Total
16	CL&P	3.10% (p)	$ 11,131	$ 32,381	$ 101,106	$ 105,012	$ 249,629
17	NSTAR Electric	8.10% (p)	$ 29,084	$ 84,608	$ 264,179	$ 274,385	$ 652,256
18	PSNH	1.00% (p)	$ 3,591	$ 10,445	$ 32,615	$ 33,875	$ 80,525
19	WMECO	0.30% (p)	$ 1,077	$ 3,134	$ 9,784	$ 10,162	$ 24,158
20	**Total Transmission (Sum Ln 16- Ln 19)**	12.50%	$ 44,882	$ 130,568	$ 407,684	$ 423,434	$ 1,006,568

(a) Exhibit No. ES-111, Page 3, Line 63 (B)
(b) Exhibit No. ES-111, Page 3, Line 63 (C)
(c) Exhibit No. ES-111, Page 3, Line 63 (D)
(d) Source of Inflation Rate is the quarterly, seasonally adjusted change in the Gross Domestic Product Implicit Price Deflator based on an index year of 2009 (2009 = 100) obtained from the Bureau of Labor Statistics. Calculation of the annual inflation rate can be found in Exhibit No. ES-115.
(e) Capitalization Rate represents the portion of Materials & Supply Procurement costs which were included in capitalized FERC accounts in the given year based on queries of Eversource accounting database.
(f) Depreciation Rate is calculated using Depreciation Expense from FERC Form 1, p336, Ln 12 divided by Net Utility Plant from FERC Form 1, p 110, Ln 6.
(g) Return Rate calculation is consistent with method as filed in the PTO AC Annual Informational Filing; return on equity (ROE) component is based on Eversource Distribution companies allowed ROE to be consistent with the merger cost/savings report submitted for state regulatory purposes. Depreciation Rate component see (g) above. Property Tax Rate component is calculated as Property Tax Expense divided by Net Utility Plant from FERC Form 1, p 110, Ln 6.
(h) Capitalized Savings, adjusted for Depreciation is calculated as (B), Ln 6 * (1-(C), Ln 7), for number of periods since initial savings
(i) Capitalized Savings, adjusted for Depreciation is calculated as (B), Ln 6 * (1-(D), Ln 7), for number of periods since initial savings
(j) Capitalized Savings, adjusted for Depreciation is calculated as (C), Ln 6 * (1-(D), Ln 7), for number of periods since initial savings
(k) Capitalized Savings, adjusted for Depreciation is calculated as (B), Ln 6 * (1-(E), Ln 7), for number of periods since initial savings
(l) Capitalized Savings, adjusted for Depreciation is calculated as (C), Ln 6 * (1-(E), Ln 7), for number of periods since initial savings
(m) Capitalized Savings, adjusted for Depreciation is calculated as (D), Ln 6 * (1-(E), Ln 7), for number of periods since initial savings
(n) Exhibit No. ES-103, Page 4, Line 13
(o) Annual savings multiplied by .75 to prorate and only include savings through September 30, 2015.
(p) Source is Exhibit No. ES-116

PUBLIC VERSION
PROTECTED MATERIALS REDACTED

Eversource Energy Service Company
Materials & Supply Procurement Savings Exhibit

		Savings		
	(A)	(B)	(C)	(D)
	Other Vendors	2012	2013	2014
1	[redacted]	$ -	$ 17,204	$ 17,204
2		$ -	$ -	$ 20,125
3		$ -	$ -	$ 111,051
4		$ -	$ -	$ 707
5		$ 277,500	$ -	$ 86,961
6		$ 3,270	$ -	$ -
7		$ 20,000	$ -	$ -
8		$ -	$ 13,512	$ 5,140
9		$ -	$ 13,180	$ 13,180
10		$ -	$ 37,417	$ -
11		$ -	$ 16,467	$ -
12		$ -	$ -	$ 8,200
13		$ -	$ 212,000	$ -
14		$ -	$ 64,500	$ 66,000
15		$ -	$ -	$ 193,305
16		$ -	$ -	$ 69,064
17		$ -	$ -	$ 80,994
18		$ -	$ 5,132	$ 9,446
19		$ -	$ 779,318	$ 2,403,594
20		$ -	$ -	$ 3,540
21		$ -	$ 236,990	$ -
22		$ 600,000	$ 358,057	$ 2,052,218
23		$ -	$ -	$ 111,322
24		$ 150,000	$ -	$ -
25		$ -	$ -	$ 505,890
26		$ -	$ 40,934	$ -
27		$ 80,000	$ -	$ 243,858
28		$ -	$ 200,371	$ -
29		$ -	$ -	$ 135,116
30		$ -	$ 61,813	$ 1,650,000
31		$ -	$ 79,356	$ 31,347
32		$ -	$ 1,333	$ -
33		$ -	$ -	$ 13,026
34		$ -	$ -	$ 1,121,873
35		$ 15,000	$ -	$ 3,200

Eversource Energy Service Company
Materials & Supply Procurement Savings Exhibit

		Savings		
	(A)	(B)	(C)	(D)
	Vendor	2012	2013	2014
36	[redacted]	$ 166,000	$ -	$ -
37		$ -	$ -	$ 12,131
38		$ -	$ -	$ 88,360
39		$ -	$ 37,953	$ -
40		$ -	$ -	$ 67,926
41		$ -	$ 38,343	$ 22,850
42		$ -	$ 55,094	$ 55,094
43		$ -	$ 64,500	$ -
44		$ -	$ -	$ 12,977
45		$ -	$ 101,058	$ 248,760
46		$ 17,500	$ 36,000	$ 40,000
47		$ -	$ -	$ 11,468
48		$ -	$ 10,052	$ 10,052
49		$ -	$ -	$ 125,000
50		$ -	$ -	$ 786
51		$ -	$ -	$ 10,000
52		$ 12,300	$ -	$ -
53		$ -	$ 10,773	$ -
54		$ -	$ 13,731	$ -
55		$ -	$ 40,000	$ -
56		$ -	$ -	$ 25,000
57		$ -	$ -	$ 5,299
58		$ -	$ 2,362	$ -
59		$ 156,000	$ -	$ 408
60		$ -	$ -	$ 31,500
61		$ -	$ -	$ 25,529
62		$ -	$ 610,000	$ 420,000
63	**Total Savings (Sum Ln 1- Ln 62)**	$ 1,497,570	$ 3,157,450	$ 10,169,501

Following the merger, Eversource consolidated the procurement contracts of Legacy NSTAR and Legacy NU by evaluating common vendors to both and renegotiating such contracts, realizing savings due to both consolidation of vendors as well as vendor concessions given to Eversource due to the merged entity's bargaining power. For many contract services, Eversource conducted a competitive bidding process that resulted in the selection of one post-merger vendor. Eversource also reviewed the materials function across the enterprise, leading to over 100 duplicate items being eliminated, resulting in a lower ongoing material cost.

Exhibit No. ES-112

Administrative and General Overhead Savings Exhibit

Eversource Energy Service Company

Eversource Energy Service Company
Administrative and General Overhead Savings Exhibit

		Savings				
	(A)	(B)	(C)	(D)	(E)	(F)
		2012	**2013**	**2014**	**2015**	**Total**
1	Savings	$ -	$ 681,399 (a)	$ 926,434 (b)	$ 926,434	
2	Inflation Rate (c)				1.06%	
3	Total Administrative & General Overhead Savings ((Ln 1 * Ln 2) + Ln 1)	$ -	$ 681,399	$ 926,434	$ 936,254	
4	Capitalization Rate (d)		12.84%	13.77%	14.32%	
5	Total O&M Savings (Ln 3*(1-Ln 4))	$ -	$ 593,903	$ 798,864	$ 802,183	
6	Total Capitalized Savings (Ln 3- Ln 5)	$ -	$ 87,496	$ 127,570	$ 134,072	
7	Depreciation Rate (e)		3.32%	3 22%	3.30%	
8	Return + Depreciation Rate + Property Tax Rate (f)		17.22%	16.48%	16.66%	
	Capitalized Savings adjusted for Depreciation					
9	2012	$ -	$ -	$ -	$ -	
10	2013	$ -	$ 87,496	$ 84,679 (g)	$ 81,817 (h)	
11	2014	$ -	$ -	$ 127,570	$ 123,360 (i)	
12	2015	$ -	$ -	$ -	$ 134,072	
13	Total (Sum Ln 9-Ln 12)	$ -	$ 87,496	$ 212,249	$ 339,249	
14	Revenue Requirements (Ln 8 * Ln 13)	$ -	$ 15,063	$ 34,979	$ 56,519	
15	A&G Overhead Savings and Revenue Requirements (Ln 5 + Ln 14)	$ -	$ 608,966 (j)	$ 833,843 (j)	$ 644,026 (k)	$ 2,086,835

	(G)	(H)	(I) = (B), Ln 15*(H)	(J)= (C), Ln 15*(H)	(K)= (D), Ln 15*(H)	(L)= (E), Ln 15*(H)	(M)= (I) + (J) + (K) + (L)
	Allocation to Transmission:	**Allocation %**	**2012**	**2013**	**2014**	**2015**	**Total**
16	CL&P	13 06% (l)	$ -	$ 79,531	$ 108,900	$ 84,110	$ 272,541
17	NSTAR Electric	6.64% (l)	$ -	$ 40,435	$ 55,367	$ 42,763	$ 138,566
18	PSNH	2 82% (l)	$ -	$ 17,173	$ 23,514	$ 18,162	$ 58,849
19	WMECO	2 50% (l)	$ -	$ 15,224	$ 20,846	$ 16,101	$ 52,171
20	**Total Transmission (Sum Ln 16 -Ln 19)**	25 02%	$ -	$ 152,363	$ 208,627	$ 161,135	$ 522,126

(a) Exhibit No. ES-112, Page 2, Line 8 (B)
(b) Exhibit No. ES-112, Page 2, Line 8 (C)
(c) Source of Inflation Rate is the quarterly, seasonally adjusted change in the Gross Domestic Product Implicit Price Deflator based on an index year of 2009 (2009 = 100) obtained from the Bureau of Labor Statistics. Calculation of the annual inflation rate can be found in Exhibit No. ES-115
(d) Capitalization Rate represents the portion of Administrative and General Overhead costs which were included in capitalized FERC accounts in the given year based on queries of Eversource accounting database.
(e) Depreciation Rate is calculated using Depreciation Expense from FERC Form 1, p336, Ln 12 divided by Net Utility Plant from FERC Form 1, p 110, Ln 6.
(f) Return Rate calculation is consistent with method as filed in the PTO AC Annual Informational Filing; return on equity (ROE) component is based on Eversource Distribution companies allowed ROE to be consistent with the merger cost/savings report submitted for state regulatory purposes. Depreciation Rate component see (f) above. Property Tax Rate component is calculated as Property Tax Expense divided by Net Utility Plant from FERC Form 1, p 110, Ln 6.
(g) Capitalized Savings, adjusted for Depreciation is calculated as (C), Ln 6 * (1-(D), Ln 7), for number of periods since initial savings
(h) Capitalized Savings, adjusted for Depreciation is calculated as (C), Ln 6 * (1-(E), Ln 7), for number of periods since initial savings
(i) Capitalized Savings, adjusted for Depreciation is calculated as (D), Ln 6 * (1-(E), Ln 7), for number of periods since initial savings
(j) Exhibit No. ES-103, Page 4, Line 2
(k) Annual savings multiplied by .75 to prorate and only include savings through September 30, 2015.
(l) Source is Exhibit No. ES-116

Eversource Energy Service Company
Administrative and General Overhead Savings Exhibit

		Savings	
	(A)	(B)	(C)
	Vendor	2013	2014
1	[redacted]	$ 280,300	$ 186,640
2		$ 282,000	$ 264,000
3		$ 8,500	$ 7,792
4		$ 4,908	$ 4,908
5		$ 25,000	$ -
6		$ 68,099	$ 463,094
7		$ 12,592	$ -
8	**Total Savings (Sum Ln 1- Ln 7)**	$ 681,399	$ 926,434

A&G overhead costs include office supplies, telephone expenses, employee business expenses and other miscellaneous costs. Following the merger, A&G overhead costs decreased as existing contracts were renegotiated or replaced due to Eversource's increased purchasing leverage, and as corporate personnel were reduced.

Exhibit No. ES-113

Association Dues Savings Exhibit

Eversource Energy Service Company

Eversource Energy Services Company
Association Dues Savings Exhibit

(A)	Savings (B) 2012		Savings (C) 2013		Savings (D) 2014		Savings (E) 2015		(F) Total
1 Savings	$ 68,824	(a)	$ 387,068	(b)	$ 387,068		$ 392,913		
2 Inflation Rate (c)					1.51%		1.06%		
3 Total Association Dues Savings ((Ln 1 * Ln 2) + Ln 1)	$ 68,824	(d)	$ 387,068	(d)	$ 392,913	(d)	$ 297,808	(e)	$ 1,146,613

(G) Allocation to Transmission:	(H) Allocation %		(I) = (B), Ln 3 *(H) 2012	(J)= (C), Ln 3 *(H) 2013	(K)= (D), Ln 3 *(H) 2014	(L)= (E), Ln 3 *(H) 2015	(M) = (I) + (J) + (K) + (L) Total
4 CL&P	15.93%	(f)	$ 10,964	$ 61,660	$ 62,591	$ 47,441	$ 182,655
5 NSTAR Electric	11.06%	(f)	$ 7,612	$ 42,810	$ 43,456	$ 32,938	$ 126,815
6 PSNH	3.59%	(f)	$ 2,471	$ 13,896	$ 14,106	$ 10,691	$ 41,163
7 WMECO	4.54%	(f)	$ 3,125	$ 17,573	$ 17,838	$ 13,520	$ 52,056
8 Total Transmission (Sum Ln 4 -Ln 7)	35.12%		$ 24,171	$ 135,938	$ 137,991	$ 104,590	$ 402,690

(a) Exhibit No. ES-113, Page 2, Line 5 (B)
(b) Exhibit No. ES-113, Page 2, Line 5 (C)
(c) Source of Inflation Rate is the quarterly, seasonally adjusted change in the Gross Domestic Product Implicit Price Deflator based on an index year of 2009 (2009 = 100) obtained from the Bureau of Labor Statistics. Calculation of the annual inflation rate can be found in Exhibit No. ES-115
(d) Exhibit No. ES-103, Page 4, Line 11
(e) Annual savings multiplied by .75 to prorate and only include savings through September 30, 2015.
(f) Source is Exhibit No. ES-116

Eversource Energy Services Company
Association Dues Savings Exhibit

	(A) Vendor	Savings (B) 2012		Savings (C) 2013	
1	EEI Contract	$ 32,934		$ 103,043	
2	EEI Foundation Participation	$ -		$ 30,000	
3	EEI Industry Issues	$ -		$ 108,526	
4	Conference Board	$ 35,890		$ 35,890	
5	Pioneer Valley Planning Commission	$ -		$ 5,600	
6	Torrington Economic Development	$ -		$ 1,000	
7	Harford Ihub	$ -		$ 10,000	
8	SECTR (Sector Economic Gardening)	$ -		$ 11,500	
9	EDC of Western Massachusetts	$ -		$ 5,600	
10	Society of Industrial and Office Real Estate	$ -		$ 1,500	
11	Industrial Asset Management Council	$ -		$ 1,500	
12	Utility Economic Development Assoc (UEDA)	$ -		$ 6,000	
13	CT Partnership for Balanced Growth	$ -		$ 25,000	
14	CT Technology Council	$ -		$ 7,500	
15	Campaign for Home Energy Assistance	$ -		$ 2,500	
16	BEACON (Biomedical Engineering Alliance & Consortium	$ -		$ 5,000	
17	Chamber Savings	$ -		$ 19,409	
18	Boston College Center for Corp. Citizenship	$ -		$ 7,500	
19	Total Savings (Sum Ln 1- Ln 18)	$ 68,824	(a)	$ 387,068	(b)

(a) Exhibit No. ES-113, Page 3, Line 5 (E)
(b) Exhibit No. ES-113, Page 3, Line 5 (F)

Eversource Energy Services Company
Association Dues Savings Exhibit

		Expenses			Savings	
	(A)	(B)	(C)	(D)	(E) = (B) - (C)	(F) = (B) - (D)
	Company	2011	2012	2013	2012	2013
1	EEI Contract	$ 1,188,305	$ 1,155,371	$ 1,085,262	$ 32,934	$ 103,043
2	EEI Foundation Participation	$ 30,000	$ 30,000	$ -	$ -	$ 30,000
3	EEI Industry Issues	$ 108,526	$ 108,526	$ -	$ -	$ 108,526
4	Conference Board	$ 35,890	$ -	$ -	$ 35,890	$ 35,890
5	Pioneer Valley Planning Commission	$ 5,600	$ 5,600	$ -	$ -	$ 5,600
6	Torrington Economic Development	$ 1,000	$ 1,000	$ -	$ -	$ 1,000
7	Harford Ihub	$ 10,000	$ 10,000	$ -	$ -	$ 10,000
8	SECTR (Sector Economic Gardening)	$ 11,500	$ 11,500	$ -	$ -	$ 11,500
9	EDC of Western Massachusetts	$ 5,600	$ 5,600	$ -	$ -	$ 5,600
#	Society of Industrial and Office Real Estate	$ 1,500	$ 1,500	$ -	$ -	$ 1,500
#	Industrial Asset Management Council	$ 1,500	$ 1,500	$ -	$ -	$ 1,500
#	Utility Economic Development Assoc (UEDA)	$ 6,000	$ 6,000	$ -	$ -	$ 6,000
#	CT Partnership for Balanced Growth	$ 25,000	$ 25,000	$ -	$ -	$ 25,000
#	CT Technology Council	$ 7,500	$ 7,500	$ -	$ -	$ 7,500
#	Campaign for Home Energy Assistance	$ 2,500	$ 2,500	$ -	$ -	$ 2,500
#	BEACON (Biomedical Engineering Alliance & Consortium	$ 5,000	$ 5,000	$ -	$ -	$ 5,000
#	Chamber Savings	$ 19,409	$ 19,409	$ -	$ -	$ 19,409
#	Boston College Center for Corp. Citizenship	$ 7,500	$ 7,500	$ -	$ -	$ 7,500
#	Total (Sum Ln 1- Ln 18)	$ 1,472,330	$ 1,403,506	$ 1,085,262	$ 68,824	$ 387,068

Eversource, like most other companies with utility subsidiaries, is a member of a number of various associations that helps it to fulfill its mission. Following the merger close, Eversource was able to reduce certain dues, such as those for the Edison Electric Institute ("EEI") because there were duplicate dues from Legacy NU and Legacy NSTAR. As part of this process, all voluntary professional memberships and corporate sponsorships/association fees were reviewed, evaluated, and some were determined not necessary and were eliminated.

Exhibit No. ES-114

Shareholder Services Savings Exhibit

Eversource Energy Service Company

Eversource Energy Service Company
Shareholder Services Savings Exhibit

(A)	Savings (B) 2012		Savings (C) 2013		Savings (D) 2014		Savings (E) 2015		Savings (F) Total
1 Savings	$ 301,800	(a)	$ 648,800	(b)	$ 648,800		$ 658,597		
2 Inflation Rate (c)					1.51%		1.06%		
3 Total Shareholder Services Savings ((Ln 1 * Ln 2) + Ln 1)	$ 301,800	(d)	$ 648,800	(d)	$ 658,597	(d)	$ 499,184	(e)	$ 2,108,380

(G) Allocation to Transmission:	(H) Allocation %		(I) = (B), Ln 3 *(H) 2012	(J) = (C), Ln 3 *(H) 2013	(K) = (D), Ln 3 *(H) 2014	(L) = (E), Ln 3 *(H) 2015	(M) = (I) + (J) + (K) + (L) Total
4 CL&P	6.96%	(f)	$ 21,005	$ 45,156	$ 45,838	$ 34,743	$ 146,743
5 NSTAR Electric	7.44%	(f)	$ 22,454	$ 48,271	$ 49,000	$ 37,139	$ 156,864
6 PSNH	1.50%	(f)	$ 4,527	$ 9,732	$ 9,879	$ 7,488	$ 31,626
7 WMECO	1.60%	(f)	$ 4,829	$ 10,381	$ 10,538	$ 7,987	$ 33,734
8 Total Transmission (Sum Ln 4 - Ln 7)	17.50%		$ 52,815	$ 113,540	$ 115,254	$ 87,357	$ 368,967

(a) Exhibit No ES-114, Page 2, Line 9 (B)
(b) Exhibit No ES-114, Page 2, Line 9 (C)
(c) Source of Inflation Rate is the quarterly, seasonally adjusted change in the Gross Domestic Product Implicit Price Deflator based on an index year of 2009 (2009 100) obtained from the Bureau of Labor Statistics. Calculation of the annual inflation rate can be found in Exhibit No. ES-115.
(d) Exhibit No. ES-103, Page 4, Line 8
(e) Annual savings multiplied by .75 to prorate and only include savings through September 30, 2015.
(f) Source is Exhibit No. ES-116

Eversource Energy Service Company
Shareholder Services Savings Exhibit

	(A) Vendor	Savings (Costs) (B) 2012		Savings (Costs) (C) 2013	
1	Transfer Agent Services	$ 167,000		$ 326,000	
2	Investor Relations Services	$ 28,000		$ 28,000	
3	Stock Surveillance Services	$ 23,500		$ 23,500	
4	Proxy Solicitor	$ 15,000		$ 15,000	
5	Annual Meeting, Proxy Mailings Services	$ 22,800		$ 22,800	
6	Annual Report to Shareholders	$ 47,500		$ 47,500	
7	NYSE Listing Fee	$ (37,000)		$ (37,000)	
8	Rating Agencies	$ 35,000		$ 223,000	
9	Total (Sum Ln 1- Ln 8)	$ 301,800	(a)	$ 648,800	(b)

(a) Exhibit No ES-114, Page 3, Line 9 (E)
(b) Exhibit No ES-114, Page 3, Line 9 (F)

Eversource Energy Service Company
Shareholder Services Savings Exhibit

	Vendor	Expenses (B) 2011	Expenses (C) 2012	Expenses (D) 2013	Savings (Costs) (E) = (B) - (C) 2012	Savings (Costs) (F) = (B) - (D) 2013
1	Transfer Agent Services	$ 650,000	$ 483,000	$ 324,000	$ 167,000	$ 326,000
2	Investor Relations Services	$ 39,600	$ 11,600	$ 11,600	$ 28,000	$ 28,000
3	Stock Surveillance Services	$ 37,000	$ 13,500	$ 13,500	$ 23,500	$ 23,500
4	Proxy Solicitor	$ 35,000	$ 20,000	$ 20,000	$ 15,000	$ 15,000
5	Annual Meeting, Proxy Mailings Services	$ 294,600	$ 271,800	$ 271,800	$ 22,800	$ 22,800
6	Annual Report to Shareholders	$ 128,500	$ 81,000	$ 81,000	$ 47,500	$ 47,500
7	NYSE Listing Fee (a)	$ 279,000	$ 316,000	$ 316,000	$ (37,000)	$ (37,000)
8	Rating Agencies (b)	$ 523,000	$ 488,000	$ 300,000	$ 35,000	$ 223,000
9	Total (Sum Ln 1- Ln 8)	$ 1,986,700	$ 1,684,900	$ 1,337,900	$ 301,800	$ 648,800

Eversource examined its costs for Shareholder Services as compared to the combined Shareholder Services costs that Legacy NU and Legacy NSTAR incurred in 2011, the year before the merger. Following the close of the merger, Eversource was able to realize savings in the area of Shareholder Services due to the elimination of duplicative shareholder related activities, such as conducting one annual shareholder meeting versus two (one for each of Legacy NU and Legacy NSTAR), reduced proxy services and payment of stock exchange fees. Additionally, incremental costs incurred per additional shareholder were reduced for Eversource due to economies of scale that Legacy NU and Legacy NSTAR were unable to achieve as standalone companies.

(a) Incremental annual fees experienced due to the exchange ratio of Northeast Utilities shares for NSTAR shares.
(b) Eversource negotiated lower rating agency fees due to the larger size of the merged company.

Exhibit No. ES-115

Inflation Rate Support (GDP)

Eversource Energy Service Company

Eversource Energy Service Company
Inflation Rate Support (GDP)

Year	Quarter	GDP	Annual Average	Annual Period % Change	
2011	1	103.145			
2011	2	103.768			
2011	3	103.917			
2011	4	104.466	103.824		
2012	1	104.943			
2012	2	105.508			
2012	3	105.935			
2012	4	106.363	105.687	1.79%	
2013	1	106.623			
2013	2	107.128			
2013	3	107.589			
2013	4	108.009	107.337	1.56%	
2014	1	108.606			
2014	2	109.044	108.312 (a)		
2014	3	109.067			
2014	4	109.099	108.954	1.51%	
2015	1	109.674			
2015	2	110.007	109.462 (b)	1.06%	((b) - (a)) / (a)

Source of Inflation Rate is the quarterly, seasonally adjusted change in the Gross Domestic Product (GDP) Implicit Price Deflator based on an index year of 2009 (2009 = 100) obtained from the Bureau of Labor Statistics website, www.bls.gov.

Exhibit No. ES-116

Allocation Percentage Support

Eversource Energy Service Company

Eversource Energy Service Company
Allocation Percentage Support

			Merger Net Savings Allocation												
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
Line	Category	Allocation Methodology (a)	CL&P D	CL&P T	YGS	WMECO D	WMECO T	NSTAR Gas	NSTAR D	NSTAR T	PSNH D	PSNH T	PSNH G	Unreg	Total
1	Total Labor Savings	Labor	26.95%	13.06%	4.32%	4.22%	2.50%	5.57%	25.48%	6.64%	6.63%	2.82%	1.59%	0.22%	100.00%
2	Administrative & General Overhead	Labor	26.95%	13.06%	4.32%	4.22%	2.50%	5.57%	25.48%	6.64%	6.63%	2.82%	1.59%	0.22%	100.00%
3	Advertising	Gross Plant Assets / Net Income	18.66%	15.93%	5.59%	3.26%	4.54%	3.83%	21.31%	11.06%	6.41%	3.59%	5.69%	0.13%	100.00%
4	Benefits	Labor	26.95%	13.06%	4.32%	4.22%	2.50%	5.57%	25.48%	6.64%	6.63%	2.82%	1.59%	0.22%	100.00%
5	Insurance	Gross Plant Assets / Net Income	18.66%	15.93%	5.59%	3.26%	4.54%	3.83%	21.31%	11.06%	6.41%	3.59%	5.69%	0.13%	100.00%
6	Information Systems	Labor	26.95%	13.06%	4.32%	4.22%	2.50%	5.57%	25.48%	6.64%	6.63%	2.82%	1.59%	0.22%	100.00%
7	Professional Services	Gross Plant Assets / Net Income	18.66%	15.93%	5.59%	3.26%	4.54%	3.83%	21.31%	11.06%	6.41%	3.59%	5.69%	0.13%	100.00%
8	Shareholder Services	Operating Revenues	25.80%	6.96%	6.02%	4.73%	1.60%	5.32%	27.59%	7.44%	6.18%	1.50%	6.86%	0.00%	100.00%
9	Directors Fees	Gross Plant Assets / Net Income	18.66%	15.93%	5.59%	3.26%	4.54%	3.83%	21.31%	11.06%	6.41%	3.59%	5.69%	0.13%	100.00%
10	Association Dues	Gross Plant Assets / Net Income	18.66%	15.93%	5.59%	3.26%	4.54%	3.83%	21.31%	11.06%	6.41%	3.59%	5.69%	0.13%	100.00%
11	Materials & Supply Procurement	% of O&M	27.40%	3.10%	5.60%	5.40%	0.30%	6.80%	31.10%	8.10%	4.30%	1.00%	6.90%	0.00%	100.00%
12	Contract Services	% of O&M	27.40%	3.10%	5.60%	5.40%	0.30%	6.80%	31.10%	8.10%	4.30%	1.00%	6.90%	0.00%	100.00%
13	Merger Related Cost	Gross Plant Assets	22.14%	13.86%	6.41%	3.51%	3.73%	4.26%	20.81%	8.16%	7.22%	3.14%	5.10%	1.66%	100.00%

(a) Eversource examined each of these categories and based on the nature of the category, allocated them to each subsidiary and business segment using pre-determined allocators specifically identified in Eversource Service s FERC Form 60. The one exception to this is the O&M allocator, which is not included among the FERC Form 60 allocators. The O&M allocator was calculated as the ratio of each subsidiary and business segment s O&M to the total O&M for all subsidiaries/business segments.

Exhibit No. ES-117

Cost of Debt Decline

Eversource Energy Service Company

Cost of Debt Decline
For the years 2012-2014
Total Eversource Cost of Debt

Line	Component (A)		(B) 2012			(C) 2013			(D) 2014	
	Debt Expense									
1	CL&P	$	126,546,758	(a)	$	131,000,625	(b)	$	135,578,285	(c)
2	NSTAR (Line 7 * 12)	$	75,582,176		$	76,993,348		$	75,114,639	
3	PSNH	$	44,887,056	(a)	$	41,840,040	(b)	$	43,820,774	(c)
4	WMECO	$	23,379,723	(a)	$	23,475,395	(b)	$	24,478,251	(c)
5	Total ES (Sum of Lines 1 - 4)	$	270,395,713		$	273,309,408		$	278,991,949	
	Outstanding Debt									
6	CL&P	$	2,263,774,475	(a)	$	2,343,008,787	(b)	$	2,529,279,559	(c)
7	NSTAR	$	1,594,560,685	(a)	$	1,794,716,740	(b)	$	1,792,712,148	(c)
8	PSNH	$	990,148,248	(a)	$	1,016,601,510	(b)	$	1,056,236,668	(c)
9	WMECO	$	491,619,003	(a)	$	556,264,418	(b)	$	568,072,183	(c)
10	Total ES (Sum of Lines 6 - 9)	$	5,340,102,411		$	5,710,591,455		$	5,946,300,558	
	Cost of Debt									
11	CL&P (Line 1 / 6)		5.59%			5.59%			5.36%	
12	NSTAR		4.74%	(a)		4.29%	(b)		4.19%	(c)
13	PSNH (Line 3 / 8)		4.53%			4.12%			4.15%	
14	WMECO (Line 4 / 9)		4.76%			4.22%			4.31%	
15	Total ES (Sum of Lines 11 - 14)		5.06%			4.79%			4.69%	

Notes:
(a) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2013 under Docket No. RT04-2-000.
(b) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2014 under Docket No. RT04-2-000.
(c) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.

Exhibit No. ES-118

Non-Fuel Electric O&M Analysis

Eversource Energy Service Company

Eversource Energy Service Company
Non-Fuel Electric O&M Analysis
2011 through 2014, Change in Electric O&M vs. EEI Member Companies
$000s

	Total Electric O&M Expense		Less Power Production Expense		Less Transmission By Others		Less Uncollectible Expense		Less Customer Service Expense		Adjusted O&M		Adjusted O&M Percentage Change
Company Name	**2012**	**2011**	**2012**	**2011**	**2012**	**2011**	**2012**	**2011**	**2012**	**2011**	**2012**	**2011**	**2012 vs. 2011**
Eversource Energy	4,111,323	4,292,814	2,153,777	2,451,603	315,238	311,604	95,439	67,240	348,875	305,770	1,197,994	1,156,597	3.6%
ALLETE, Inc.	601,313	590,988	442,003	435,807	27,697	21,537	800	905	10,798	12,946	120,015	119,793	0.2%
Alliant Energy Corporation	1,833,983	1,885,959	1,154,110	1,234,171	341,263	323,783	8,375	8,419	84,258	81,077	245,977	238,509	3.1%
Ameren Corporation	3,411,007	3,987,805	2,332,843	2,869,097	42,789	37,948	22,003	29,951	60,074	46,475	953,298	1,004,334	-5.1%
American Electric Power Co., Inc.	10,426,134	11,458,301	8,262,253	9,372,991	295,058	242,303	106,749	90,145	143,221	139,219	1,618,853	1,613,643	0.3%
Avista Corporation	714,845	750,210	536,329	579,224	17,552	17,490	2,130	2,632	24,468	28,480	134,366	122,384	9.8%
Black Hills Corporation	396,356	427,897	273,697	303,721	31,570	37,837	1,460	1,264	1,688	1,575	87,941	83,500	5.3%
CenterPoint Energy, Inc.	930,113	888,532	-	-	416,979	385,516	1,174	1,196	35,780	32,639	476,180	469,181	1.5%
Cleco Corporation	546,685	645,611	425,193	519,705	10,439	9,348	841	1,568	3,396	4,833	106,816	110,157	-3.0%
CMS Energy Corporation	2,665,598	2,644,143	1,861,867	1,855,458	262,404	248,478	24,934	33,630	84,419	78,961	431,974	427,616	1.0%
Consolidated Edison, Inc.	4,930,390	5,124,492	2,499,505	2,942,994	(189)	-	78,624	79,042	20,276	10,059	2,332,174	2,092,397	11.5%
Dominion Resources, Inc.	4,210,127	4,427,419	3,391,878	3,545,198	(24,816)	(15,266)	28,070	32,448	24,441	18,079	790,554	846,960	-6.7%
DTE Energy Company	3,166,792	3,095,707	1,931,754	1,865,656	246,593	285,616	42,285	50,815	64,816	52,658	881,344	840,962	4.8%
Duke Energy Corporation (a)	13,581,980	13,281,616	10,582,165	10,331,441	40,281	86,768	32,611	50,719	123,879	144,700	2,803,044	2,667,988	5.1%
Edison International	7,502,290	7,563,557	4,667,525	4,789,608	26,685	5,908	34,494	31,040	551,126	565,278	2,222,460	2,171,723	2.3%
El Paso Electric Company	545,248	586,841	364,846	412,627	4,713	6,578	3,087	6,207	33	619	172,569	160,810	7.3%
Empire District Electric Company	303,734	319,841	212,122	233,149	7,223	5,978	2,672	3,099	1,362	1,332	80,355	76,283	5.3%
Entergy Corporation	6,904,805	7,883,462	5,628,918	6,664,673	11,881	39,009	18,978	22,698	38,030	26,329	1,206,998	1,130,753	6.7%
Exelon Corporation (b)	7,214,425	8,246,928	4,260,035	5,449,854	4,911	2,547	127,579	146,290	231,996	180,933	2,589,904	2,467,304	5.0%
FirstEnergy Corp.	6,766,746	7,767,982	4,580,255	5,811,216	345,747	249,935	74,999	54,095	310,211	286,442	1,455,534	1,366,294	6.5%
Great Plains Energy Inc.	1,331,967	1,380,769	913,253	945,672	35,412	30,232	1,639	4,898	14,244	12,924	367,419	387,043	-5.1%
Hawaiian Electric Industries, Inc.	2,416,088	2,333,063	2,155,073	2,086,785	-	-	2,954	4,192	1,571	1,042	256,490	241,044	6.4%
DACORP, Inc.	670,513	709,102	384,341	428,274	6,294	6,462	4,513	4,270	33,737	44,035	241,628	226,061	6.9%
MDU Resources Group, Inc.	143,533	132,391	98,828	88,089	1,307	981	425	400	116	302	42,857	42,619	0.6%
MGE Energy, Inc.	254,309	243,182	151,481	146,728	29,703	29,063	1,365	1,468	7,887	6,967	63,873	58,956	8.3%
NextEra Energy, Inc.	6,015,660	6,663,769	4,910,784	5,632,612	42,147	40,771	9,561	7,193	108,647	114,081	944,521	869,112	8.7%
NiSource Inc.	958,325	952,445	679,632	708,894	-	21	1,604	355	-	-	277,089	243,175	13.9%
NorthWestern Corporation	469,536	501,544	319,801	358,942	10,219	11,368	1,716	2,094	4,657	4,663	133,143	124,477	7.0%
OGE Energy Corp.	1,443,861	1,567,119	1,073,295	1,211,305	905	642	3,391	5,826	19,185	22,326	347,085	327,020	6.1%
Otter Tail Corporation	230,876	224,339	144,587	142,007	5,746	2,524	598	406	6,669	7,195	73,276	72,207	1.5%
Pepco Holdings, Inc.	2,835,523	3,132,138	2,021,402	2,302,896	-	-	33,118	42,853	10,444	7,515	770,559	778,874	-1.1%
PG&E Corporation	7,593,271	7,227,913	4,805,770	4,538,153	17,233	21,532	57,159	56,655	672,418	684,749	2,040,691	1,926,824	5.9%
Pinnacle West Capital Corp.	1,911,889	1,961,708	1,400,721	1,475,752	18,827	17,010	5,290	5,752	74,898	69,637	412,153	393,557	4.7%
PNM Resources, Inc.	894,807	877,922	552,501	555,381	61,551	56,572	3,367	3,769	1,090	1,150	276,298	261,050	5.8%
Portland General Electric Co.	1,166,655	1,199,357	785,095	821,396	68,731	68,711	6,698	10,187	9,949	9,914	296,182	289,149	2.4%
PPL Corporation	2,962,743	3,055,724	1,941,112	2,080,397	62,920	64,150	38,271	42,336	127,828	130,262	792,612	738,579	7.3%
Public Service Ent. Group Inc.	3,074,938	3,440,928	2,188,317	2,675,649	-	-	82,092	71,695	161,822	144,713	642,707	548,871	17.1%
					611	562	5,747	5,560	4,582	3,004	267,988	258,791	3.6%
					5,165	4,262	3,854	4,109	156,782	152,960	679,276	687,676	-1.2%
Southern Company	9,517,891	11,031,478	7,467,822	8,940,247	5,623	4,375	33,310	63,322	137,960	119,269	1,873,176	1,904,265	-1.6%
TECO Energy, Inc.	1,203,642	1,227,284	954,208	995,224	14	221	2,321	2,609	46,335	42,486	200,764	186,744	7.5%
U L Holdings Corporation	456,061	506,534	161,268	187,187	79,468	77,997	22,713	20,185	24,444	32,474	168,168	188,691	-10.9%
Unitil Corporation	144,126	145,955	80,325	88,549	25,145	21,984	2,112	2,107	6,194	5,775	30,350	27,540	10.2%
Vectren Corporation	350,851	393,348	268,470	313,411	-	-	1,735	2,416	80	98	80,566	77,423	4.1%
Westar Energy, Inc.	1,392,253	1,386,476	870,741	910,855	5,401	6,583	6,115	8,140	2,399	2,456	507,597	458,442	10.7%
Wisconsin Energy Corporation	2,316,109	2,501,745	1,718,693	1,777,700	258,999	265,640	1,272	45,222	(23,502)	56,996	360,647	356,187	1.3%
Xcel Energy Inc.	6,329,597	6,732,048	4,751,019	5,206,080	206,141	173,360	25,454	32,989	237,982	242,827	1,109,001	1,076,792	3.0%
Average % Change, Excluding Eversource													4.0%

(a) 2011 includes Progress Energy electric O&M.
(b) 2011 includes Commonwealth electric O&M.

Eversource Energy Service Company
Non-Fuel Electric O&M Analysis
2011 through 2014, Change in Electric O&M vs. EEI Member Companies
$000s

	Total Electric O&M Expense		Less Power Production Expense		Less Transmission By Others		Less Uncollectible Expense		Less Customer Service Expense		Adjusted O&M		Adjusted O&M Percentage Change
Company Name	**2013**	**2011**	**2013**	**2011**	**2013**	**2011**	**2013**	**2011**	**2013**	**2011**	**2013**	**2011**	**2013 vs. 2011**
Eversource Energy	4,285,535	4,292,814	2,278,171	2,451,603	422,878	311,604	64,216	67,240	362,365	305,770	1,157,905	1,156,597	0.1%
ALLETE, Inc.	635,414	590,988	465,792	435,807	29,975	21,537	904	905	13,712	12,946	125,031	119,793	4.4%
Alliant Energy Corporation	1,893,631	1,885,959	1,139,078	1,234,171	418,275	323,783	12,241	8,419	61,220	81,077	262,817	238,509	10 2%
Ameren Corporation	2,761,426	3,987,805	1,670,062	2,869,097	44,343	37,948	25,677	29,951	97,391	46,475	923,953	1,004,334	-8 0%
American Electric Power Co., Inc.	10,944,039	11,458,301	8,637,102	9,372,991	389,224	242,303	185,254	90,145	160,831	139,219	1,571,628	1,613,643	-2 6%
Avista Corporation	684,483	750,210	521,213	579,224	17,927	17,490	2,535	2,632	20,642	28,480	122,166	122,384	-0 2%
Black Hills Corporation	422,029	427,897	285,718	303,721	34,615	37,837	1,630	1,264	1,535	1,575	98,531	83,500	18 0%
CenterPoint Energy, Inc.	1,032,650	888,532	-	-	497,842	385,516	229	1,196	39,366	32,639	495,213	469,181	5 5%
Cleco Corporation	607,950	645,611	483,856	519,705	10,828	9,348	1,233	1,568	3,834	4,833	108,199	110,157	-1 8%
CMS Energy Corporation	2,734,358	2,644,143	1,875,314	1,855,458	291,978	248,478	32,592	33,630	82,600	78,961	451,874	427,616	5.7%
Consolidated Edison, Inc.	4,920,493	5,124,492	2,559,965	2,942,994	(11)	-	70,283	79,042	24,091	10,059	2,266,165	2,092,397	8 3%
Dominion Resources, Inc.	4,100,764	4,427,419	3,369,779	3,545,198	(21,119)	(15,266)	33,708	32,448	24,462	18,079	693,934	846,960	-18.1%
DTE Energy Company	3,051,527	3,095,707	1,867,798	1,865,656	248,123	285,616	52,799	50,815	60,539	52,658	822,268	840,962	-2 2%
Duke Energy Corporation (a)	13,420,177	13,281,616	10,550,674	10,331,441	29,999	86,768	46,846	50,719	135,227	144,700	2,657,431	2,667,988	-0.4%
Edison International	8,318,866	7,563,557	5,530,729	4,789,608	31,884	5,908	36,008	31,040	504,509	565,278	2,215,736	2,171,723	2 0%
El Paso Electric Company	581,685	586,841	400,030	412,627	5,487	6,578	2,098	6,207	6	619	174,064	160,810	8 2%
Empire District Electric Company	310,360	319,841	208,919	233,149	11,271	5,978	2,968	3,099	1,675	1,332	85,527	76,283	12.1%
Entergy Corporation	8,028,740	7,883,462	6,663,130	6,664,673	18,034	39,009	22,474	22,698	50,175	26,329	1,274,927	1,130,753	12 8%
Exelon Corporation (b)	5,942,847	8,246,928	3,169,179	5,449,854	5,994	2,547	125,346	146,290	243,980	180,933	2,398,348	2,467,304	-2 8%
FirstEnergy Corp.	5,728,633	7,767,982	4,193,099	5,811,216	444,603	249,935	75,788	54,095	280,595	286,442	734,548	1,366,294	-46 2%
Great Plains Energy Inc.	1,404,486	1,380,769	948,906	945,672	53,220	30,232	-	4,898	23,386	12,924	378,974	387,043	-2.1%
Hawaiian Electric Industries, Inc.	2,295,673	2,333,063	2,027,200	2,086,785	-	-	3,545	4,192	11,699	1,042	253,229	241,044	5.1%
DACORP, Inc.	778,660	709,102	488,307	428,274	5,637	6,462	5,805	4,270	42,691	44,035	236,220	226,061	4 5%
MDU Resources Group, Inc.	160,722	132,391	109,315	88,089	1,706	981	700	400	92	302	48,909	42,619	14 8%
MGE Energy, Inc.	263,110	243,182	160,149	146,728	33,070	29,063	1,455	1,468	7,147	6,967	61,289	58,956	4 0%
NextEra Energy, Inc.	5,457,673	6,663,769	4,405,274	5,632,612	40,117	40,771	8,773	7,193	108,634	114,081	894,875	869,112	3 0%
NiSource Inc.	1,002,903	952,445	713,204	708,894	-	21	2,584	355	-	-	287,115	243,175	18.1%
NorthWestern Corporation	581,942	501,544	415,236	358,942	10,023	11,368	2,837	2,094	4,757	4,663	149,089	124,477	19 8%
OGE Energy Corp.	1,512,903	1,567,119	1,145,684	1,211,305	547	642	2,660	5,826	25,677	22,326	338,335	327,020	3 5%
Otter Tail Corporation	251,217	224,339	151,772	142,007	9,893	2,524	760	406	6,929	7,195	81,863	72,207	13.4%
Pepco Holdings, Inc.	2,823,088	3,132,138	2,024,940	2,302,896	-	-	34,682	42,853	6,092	7,515	757,374	778,874	-2 8%
PG&E Corporation	8,305,479	7,227,913	5,574,595	4,538,153	15,706	21,532	44,903	56,655	610,178	684,749	2,060,097	1,926,824	6 9%
Pinnacle West Capital Corp.	2,045,932	1,961,708	1,524,020	1,475,752	20,532	17,010	4,923	5,752	75,820	69,637	420,637	393,557	6 9%
PNM Resources, Inc.	909,713	877,922	564,219	555,381	74,038	56,572	2,849	3,769	950	1,150	267,657	261,050	2 5%
Portland General Electric Co.	1,232,425	1,199,357	837,614	821,396	74,556	68,711	6,306	10,187	11,336	9,914	302,613	289,149	4.7%
PPL Corporation	2,937,596	3,055,724	1,925,881	2,080,397	69,486	64,150	36,526	42,336	111,855	130,262	793,848	738,579	7.5%
Public Service Ent. Group Inc.	2,835,537	3,440,928	1,878,637	2,675,649	-	-	64,764	71,695	225,057	144,713	667,079	548,871	21.5%
					541	562	6,186	5,560	6,992	3,004	276,256	258,791	6.7%
					5,140	4,262	3,549	4,109	146,172	152,960	903,899	687,676	31.4%
Southern Company	9,860,683	11,031,478	7,730,404	8,940,247	5,050	4,375	34,329	63,322	142,539	119,269	1,948,361	1,904,265	2.3%
TECO Energy, Inc.	1,160,276	1,227,284	881,469	995,224	-	221	2,580	2,609	47,146	42,486	229,081	186,744	22.7%
UIL Holdings Corporation	470,613	506,534	155,177	187,187	88,206	77,997	19,877	20,185	22,968	32,474	184,385	188,691	-2.3%
Unitil Corporation	144,998	145,955	73,074	88,549	30,619	21,984	2,433	2,107	6,820	5,775	32,052	27,540	16.4%
Vectren Corporation	366,519	393,348	277,606	313,411	-	-	1,487	2,416	99	98	87,327	77,423	12.8%
Westar Energy, Inc.	1,465,028	1,386,476	928,136	910,855	5,285	6,583	6,659	8,140	2,643	2,456	522,305	458,442	13.9%
Wisconsin Energy Corporation	2,449,255	2,501,745	1,787,928	1,777,700	259,091	265,640	28,141	45,222	50,142	56,996	323,953	356,187	-9.0%
Xcel Energy Inc.	6,863,045	6,732,048	5,175,299	5,206,080	236,607	173,360	30,553	32,989	233,223	242,827	1,187,363	1,076,792	10.3%
Average % Change, Excluding Eversource													5.2%

(a) 2011 includes Progress Energy electric O&M.
(b) 2011 includes Commonwealth electric O&M.

Eversource Energy Service Company
Non-Fuel Electric O&M Analysis
2011 through 2014, Change in Electric O&M vs. EEI Member Companies
$000s

	Total Electric O&M Expense		Less Power Production Expense		Less Transmission By Others		Less Uncollectible Expense		Less Customer Service Expense		Adjusted O&M		Adjusted O&M Percentage Change
Company Name	**2014**	**2011**	**2014**	**2011**	**2014**	**2011**	**2014**	**2011**	**2014**	**2011**	**2014**	**2011**	**2014 vs. 2011**
Eversource Energy	4,559,916	4,292,814	2,596,333	2,451,603	397,059	311,604	75,323	67,240	418,347	305,770	1,072,854	1,156,597	-7.2%
ALLETE, Inc.	678,733	590,988	485,050	435,807	42,752	21,537	1,166	905	12,027	12,946	137,738	119,793	15.0%
Alliant Energy Corporation	1,891,582	1,885,959	1,075,395	1,234,171	447,480	323,783	12,273	8,419	85,892	81,077	270,542	238,509	13.4%
Ameren Corporation	2,793,632	3,987,805	1,612,171	2,869,097	44,498	37,948	24,077	29,951	129,946	46,475	982,940	1,004,334	-2.1%
American Electric Power Co., Inc.	11,991,236	11,458,301	9,297,623	9,372,991	575,133	242,303	201,378	90,145	143,319	139,219	1,773,783	1,613,643	9.9%
Avista Corporation	635,400	750,210	462,157	579,224	18,896	17,490	2,752	2,632	25,896	28,480	125,699	122,384	2.7%
Black Hills Corporation	440,255	427,897	298,784	303,721	37,136	37,837	1,731	1,264	1,548	1,575	101,056	83,500	21.0%
CenterPoint Energy, Inc.	1,234,751	888,532	-	-	665,559	385,516	1,649	1,196	37,938	32,639	529,605	469,181	12.9%
Cleco Corporation	783,486	645,611	641,590	519,705	18,643	9,348	1,994	1,568	3,949	4,833	117,310	110,157	6.5%
CMS Energy Corporation	2,938,150	2,644,143	2,075,977	1,855,458	327,582	248,478	32,364	33,630	104,690	78,961	397,537	427,616	-7.0%
Consolidated Edison, Inc.	5,119,607	5,124,492	2,658,070	2,942,994	(2)	-	79,077	79,042	359,635	10,059	2,022,827	2,092,397	-3.3%
Dominion Resources, Inc.	4,726,044	4,427,419	4,054,826	3,545,198	(48,452)	(15,266)	49,357	32,448	32,234	18,079	638,079	846,960	-24.7%
DTE Energy Company	3,009,947	3,095,707	1,857,634	1,865,656	264,501	285,616	49,512	50,815	74,807	52,658	763,493	840,962	-9.2%
Duke Energy Corporation (a)	13,769,728	13,281,616	11,059,836	10,331,441	37,344	86,768	11,827	50,719	110,297	144,700	2,550,424	2,667,988	-4.4%
Edison International	10,106,467	7,563,557	7,369,752	4,789,608	33,190	5,908	24,117	31,040	523,996	565,278	2,155,412	2,171,723	-0.8%
El Paso Electric Company	614,733	586,841	433,550	412,627	5,540	6,578	2,755	6,207	-	619	172,888	160,810	7.5%
Empire District Electric Company	363,253	319,841	251,468	233,149	16,466	5,978	2,892	3,099	2,512	1,332	89,915	76,283	17.9%
Entergy Corporation	8,542,268	7,883,462	7,141,357	6,664,673	56,540	39,009	28,172	22,698	75,740	26,329	1,240,459	1,130,753	9.7%
Exelon Corporation (b)	6,058,631	8,246,928	3,075,451	5,449,854	6,590	2,547	140,662	146,290	315,373	180,933	2,520,555	2,467,304	2.2%
FirstEnergy Corp.	7,036,606	7,767,982	4,514,373	5,811,216	592,275	249,935	78,072	54,095	265,918	286,442	1,585,968	1,366,294	16.1%
Great Plains Energy Inc.	1,521,506	1,380,769	1,020,138	945,672	74,720	30,232	-	4,898	33,143	12,924	393,505	387,043	1.7%
Hawaiian Electric Industries, Inc.	2,262,855	2,333,063	1,976,156	2,086,785	-	-	1,168	4,192	14,894	1,042	270,637	241,044	12.3%
DACORP, Inc.	848,565	709,102	557,628	428,274	6,081	6,462	6,716	4,270	34,150	44,035	243,990	226,061	7.9%
MDU Resources Group, Inc.	170,290	132,391	115,694	88,089	5,018	981	775	400	70	302	48,733	42,619	14.3%
MGE Energy, Inc.	242,129	243,182	146,806	146,728	33,167	29,063	1,125	1,468	6,348	6,967	54,683	58,956	-7.2%
NextEra Energy, Inc.	5,834,255	6,663,769	4,834,395	5,632,612	47,402	40,771	9,644	7,193	121,260	114,081	821,554	869,112	-5.5%
NiSource Inc.	1,097,462	952,445	792,713	708,894	-	21	3,808	355	-	-	300,941	243,175	23.8%
NorthWestern Corporation	595,434	501,544	431,989	358,942	9,507	11,368	2,521	2,094	4,722	4,663	146,695	124,477	17.8%
OGE Energy Corp.	1,669,636	1,567,119	1,274,917	1,211,305	838	642	2,395	5,826	30,831	22,326	360,655	327,020	10.3%
Otter Tail Corporation	272,808	224,339	167,331	142,007	13,428	2,524	760	406	6,761	7,195	84,528	72,207	17.1%
Pepco Holdings, Inc.	2,848,289	3,132,138	2,019,598	2,302,896	-	-	40,229	42,853	9,603	7,515	778,859	778,874	0.0%
PG&E Corporation	9,035,443	7,227,913	6,242,026	4,538,153	15,750	21,532	34,359	56,655	610,744	684,749	2,132,564	1,926,824	10.7%
Pinnacle West Capital Corp.	2,106,881	1,961,708	1,620,219	1,475,752	27,191	17,010	3,942	5,752	59,068	69,637	396,461	393,557	0.7%
PNM Resources, Inc.	941,593	877,922	600,611	555,381	85,202	56,572	3,267	3,769	655	1,150	251,858	261,050	-3.5%
Portland General Electric Co.	1,222,249	1,199,357	798,060	821,396	82,339	68,711	6,899	10,187	12,087	9,914	322,864	289,149	11.7%
PPL Corporation	3,120,462	3,055,724	2,078,728	2,080,397	84,561	64,150	45,638	42,336	120,734	130,262	790,801	738,579	7.1%
					-	-	62,774	71,695	196,034	144,713	664,145	548,871	21.0%
					3,178	562	7,010	5,560	8,973	3,004	288,995	258,791	11.7%
Sempra Energy	3,185,081	2,310,804	2,196,136	1,461,797	-	4,262	4,223	4,109	155,905	152,960	828,817	687,676	20.5%
Southern Company	10,989,261	11,031,478	8,656,220	8,940,247	6,469	4,375	42,222	63,322	153,393	119,269	2,130,957	1,904,265	11.9%
TECO Energy, Inc.	1,208,660	1,227,284	936,853	995,224	-	221	4,527	2,609	45,790	42,486	221,490	186,744	18.6%
UIL Holdings Corporation	500,238	506,534	167,560	187,187	89,955	77,997	26,787	20,185	34,420	32,474	181,516	188,691	-3.8%
Unitil Corporation	169,443	145,955	97,545	88,549	29,480	21,984	2,518	2,107	6,817	5,775	33,083	27,540	20.1%
Vectren Corporation	369,793	393,348	279,771	313,411	-	-	1,215	2,416	81	98	88,726	77,423	14.6%
Westar Energy, Inc.	1,588,381	1,386,476	1,001,057	910,855	6,865	6,583	9,313	8,140	2,904	2,456	568,242	458,442	24.0%
Wisconsin Energy Corporation	2,475,150	2,501,745	1,843,513	1,777,700	271,730	265,640	28,386	45,222	49,816	56,996	281,705	356,187	-20.9%
Xcel Energy Inc.	7,159,299	6,732,048	5,388,046	5,206,080	258,353	173,360	33,971	32,989	278,039	242,827	1,200,890	1,076,792	11.5%
Average % Change, Excluding Eversource													7.2%

(a) 2011 includes Progress Energy electric O&M.
(b) 2011 includes Commonwealth electric O&M.

Exhibit No. ES-119

Transmission O&M per Dollar of Net Transmission Plant

Eversource Energy Service Company

Eversource Energy Service Company
Transmission O&M per Dollar of Net Transmission Plant
For the years 2012-2014

Line	(A) Component		(B) 2012			(C) 2013			(D) 2014	
1	CL&P Net Transmission Plant	$	2,126,096,263	(a)	$	2,335,425,013	(c)	$	2,482,960,256	(e)
2	NSTAR Net Transmission Plant	$	1,129,211,243	(b)	$	1,350,806,836	(d)	$	1,452,683,631	(f)
3	PSNH Net Transmission Plant	$	414,836,213	(a)	$	489,187,327	(c)	$	576,890,049	(e)
4	WMECO Net Transmission Plant	$	504,079,114	(a)	$	759,264,682	(c)	$	809,579,758	(e)
5	Total Net Transmission Plant (Sum of Lines 1 - 4)	$	4,174,222,833		$	4,934,683,858		$	5,322,113,694	
6	CL&P Transmission O&M and A&G	$	75,212,877	(a)	$	70,622,497	(c)	$	75,052,282	(e)
7	NSTAR Transmission O&M and A&G	$	37,997,181	(b)	$	40,683,493	(d)	$	44,724,307	(f)
8	PSNH Transmission O&M and A&G	$	19,963,395	(a)	$	19,408,924	(c)	$	20,630,405	(e)
9	WMECO Transmission O&M and A&G	$	12,736,229	(a)	$	13,630,218	(c)	$	14,409,796	(e)
10	Total Transmission O&M and A&G (Sum of Lines 6 - 9)	$	145,909,682		$	144,345,132		$	154,816,790	
11	T O&M per Dollar of T Plant (line 10 / 5)		3.50%			2.93%			2.91%	
12	Total % Reduction 2012 - 2014 ([Line 11(D) - Line 11(B)] / Line 11(B))								-17%	

Notes:

(a) Source of information is ES's Regulatory Oversight Filing with State Regulators on July 31, 2013 pursuant to FERC Docket No. ER03-1247
(b) Source of information is the NSTAR Annual Informational Filing submitted to FERC on June 28, 2013 in Docket No. ER07-549 and ER09-1243.
(c) Source of information is ES's Regulatory Oversight Filing with State Regulators on July 31, 2014 pursuant to FERC Docket No. ER03-1247
(d) Source of information is the NSTAR Annual Informational Filing submitted to FERC on May 30, 2014 in Docket No. ER07-549 and ER09-1243.
(e) Source of information is ES's Regulatory Oversight Filing with State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(f) Source of information is the NSTAR Annual Informational Filing submitted to FERC on August 14, 2015 in Docket No. ER07-549 and ER09-1243.

Exhibit No. ES-120

Cumulative Transmission Merger-Related Savings from 2012-2022

Eversource Energy Service Company

CONFIDENTIAL ATTORNEY/CLIENT PRIVILEGED COMMUNICATION
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DO NOT FORWARD!

Eversource Energy Service Company
Cumulative Transmission Merger-Related Savings from 2012-2022

	Corporate & Administrative Labor	Information Systems	Insurance	Professional Services	Contract Services	External Directors/ Trustee Fees	Materials & Supply Procurement	Administrative & General Overhead	Association Dues	Shareholder Services	Benefits	Total
1 Total Savings from 2012-2022(a)	$547.4	$145.6	$22.8	$13.2	$64.0	$11.2	$76.1	$8.4	$3.9	$6.7	$266.6	$1,165.9
Allocation to Transmission:												
2 CL&P (b)	13.06%	13.06%	15.93%	15.93%	3.10%	15.93%	3.10%	13.06%	15.93%	6.96%	13.06%	
3 NSTAR Electric (c)	6.64%	6.64%	11.06%	11.06%	8.10%	11.06%	8.10%	6.64%	11.06%	7.44%	6.64%	
4 PSNH (d)	2.82%	2.82%	3.59%	3.59%	1.00%	3.59%	1.00%	2.82%	3.59%	1.50%	2.82%	
5 WMECO (e)	2.50%	2.50%	4.54%	4.54%	0.30%	4.54%	0.30%	2.50%	4.54%	1.60%	2.50%	
6 Total Allocation(Sum Ln 2 -Ln5)	25.02%	25.02%	35.12%	35.12%	12.50%	35.12%	12.50%	25.02%	35.12%	17.50%	25.02%	
7 Total Savings Allocated to Transmission(Ln 1* Ln6)	$137.0	$36.4	$8.0	$4.7	$8.0	$3.9	$9.5	$2.1	$1.4	$1.2	$66.7	$278.8

(a) Exhibit No. ES-103, Page 4, Total Column
(b) Exhibit No. ES-116, Page 1, (D)
(c) Exhibit No. ES-116, Page 1, (J)
(d) Exhibit No. ES-116, Page 1, (L)
(e) Exhibit No. ES-116, Page 1, (G)

SAGE MANAGEMENT CONSULTANTS, LLC

2015 MANAGEMENT AUDIT OF

THE CONNECTICUT LIGHT AND POWER COMPANY

AUTHORIZED BY THE

STATE OF CONNECTICUT
PUBLIC UTILITIES REGULATORY AUTHORITY

DEPARTMENT OF ENERGY & ENVIRONMENTAL PROTECTION
PUBLIC UTILITIES REGULATORY AUTHORITY

FINAL REPORT

January 15, 2016

SAGE in interviews or in document request responses by CL&P, or were found in publicly available information. SAGE has not made an analysis, verified, or rendered an independent judgment of the validity of the information provided by CL&P. CL&P reviewed and provided factual corrections to the draft report contents during the period beginning October 14, 2015 through December 1, 2015.

G. SUMMARY OF FINDINGS

This section contains a summarization of all audit findings from each chapter. A full discussion of each finding is contained in its respective report chapter.

II. EXECUTIVE MANAGEMENT

1. The Eversource Energy Service Company (Eversource) functionally-centralized organization structure provides clear management accountabilities for each functional area and facilitates the capture of economies of scale.
2. The centralization of utility functions and support services at the Eversource level and the rebranding of CL&P as Eversource Connecticut Electric increased the risk of the loss of local control, the reduction of cross-functional coordination, and the erosion of the CL&P Connecticut identity.
3. The NU/NSTAR merger integration has gone well.
4. Eversource has a well-developed corporate performance management system.
5. There is no Eversource or CL&P strategic planning process or plan.

III. EXTERNAL RELATIONS

1. Corporate Relations and Investor Relations have specific units and individual employees assigned to each of CL&P's major audiences.
2. Corporate Relations has a weekly "traffic call" for all of the Corporate Relations leaders; however, there is no longer a meeting or call specifically focused on Connecticut issues.
3. The Connecticut Regulatory Affairs personnel did not promptly notify the PURA regarding the Eversource Director Operations reorganization project and actions.
4. Eversource supports Connecticut by buying housing tax credits.
5. CL&P is reaching increasing numbers of customers through social media.
6. Corporate Relations is involved in securing Connecticut PURA approvals for non-CL&P Eversource projects.
7. Investor Relations has been recognized as an industry leader.

IV. ELECTRIC SUPPLY

1. Long-term load forecasting is thorough and reasonably accurate.
2. Supply procurement policies produce portfolio diversity.
3. Supply procurement processes and methods support access to reliable, competitively priced, and flexible resources.

- Labor Savings $449.1
- Corporate and Administrative Savings $276.0
- Purchasing Savings $223.0
- Total Gross Savings $948.1
- Merger-Related Costs Amortization ($164.3)
- Total Net Savings $783.8

Approximately $350 million of the net savings would be attributable to Connecticut over the ten-year period with approximately $296 million of that amount attributable to CL&P.

B. FINDINGS

1. **The Eversource functionally-centralized organization structure provides clear management accountabilities for each functional area and facilitates the capture of economies of scale.**

With the recent Operations reorganization, all major CL&P utility functions and support services have been centralized under their respective Eversource functions. Customer service is provided by a centralized Eversource customer care organization; transmission is provided by a centralized Eversource transmission function; and each support service is provided by a centralized unit, such as Human Resources and Information Technology. Further, there is a single officer or director clearly accountable for each utility function and support service. For example, the COO is responsible for all of the four Eversource Energy operating companies' electric distribution, including CL&P. Likewise, the Chief Information Officer is responsible for providing all information systems and technology to the operating companies, including CL&P. This clear assignment of responsibility and accountability for each utility function and support service is a good practice.

The centralization of utility functions and support services also enables the capture of economies of scale and the sharing of good practices across the operating companies within each function and support service. For example, the recent implementation of a single outage management system across all four electric utility operating companies spread the cost of the system over four companies and enabled better sharing of resources during storms.

2. **The centralization of utility functions and support services at the Eversource level and the rebranding of CL&P as Eversource Energy Connecticut Electric increased the risk of the loss of local control, the reduction of cross-functional coordination, and the erosion of the CL&P Connecticut identity.**

At the time of this writing, the position of President of Connecticut Electric Distribution Operations had not been filled. Prior to the Operations reorganization, the Connecticut President managed a wider scope of functions, including Distribution Engineering and several operations support functions. With the Operations reorganization, the Connecticut President will manage only Distribution Operations while Distribution Engineering and all operations support services will be provided by Eversource level centralized organizations.

The prior Connecticut President held monthly cross-functional meetings of all Connecticut focused personnel, regardless of their organization assignments. These meetings included Customer Care, Legal, Regulatory, Communications, Government Affairs, and other personnel focused on Connecticut. When the prior Connecticut President retired, these cross-functional meetings stopped. All Connecticut personnel interviewed who had participated in them reported that the meetings were valuable for cross-functional coordination.

Eversource has done a good job of assigning specific support function individuals or units to focus on Connecticut. This includes Legal, Communications, Community Relations, Government Relations, and others. It is also helpful that many Eversource functions are headquartered or have a large presence in Berlin, Connecticut. However, there is no current mechanism to coordinate the multiple Connecticut-focused personnel's efforts in Connecticut.

3. The NU/NSTAR merger integration has gone well.

The NSTAR merger began in June 2010 and closed in April 2011. The merger "made sense." NSTAR was more urban than NU and had substantial cash. NU was more suburban and had substantial capital investment opportunities. It was officially a "merger of equals" for tax purposes but, in reality, NU acquired NSTAR with the NSTAR CEO becoming the Eversource CEO. The principal NU merger team was the CEO, CFO, and General Counsel. It was a stock-for-stock transaction. The "social issues" of who would be the surviving executive team worked because of the ages of the legacy teams. For example, the NU CEO retired after the merger.

There was no specific NU/NSTAR integration plan that prescribed post-close details for the consolidation with pre-determined time tables. Instead, integration details were delegated to the executives who were selected to lead the integration efforts in each functional area and the Company achieved cost efficiencies through the implementation of best practices among the operating affiliates, through leveraging the greater size and scope of the combined organization, and through labor reductions where it was possible to reduce staffing, while continuing to meet reliability and customer-service objectives.

Prior to the merger, Merger Integration Teams (MITs) examined the structure and practices of both of the pre-merger companies and reported on the "as-is" status. The top level management team was selected before the merger. Key merger-related decisions and integration updates were communicated to employees.

As part of the merger approval process, a study was provided to regulators that showed where potential savings could be achieved in functional areas. Eversource Energy has achieved the cost efficiencies promised by the merger, while also providing the best reliability results on record. One of the Eversource Energy's regulatory commitments from the merger was to provide updates identifying the net benefits achieved from the merger by, functional area. The latest merger integration report shows the ten year projected net savings to be $996 million enterprise-wide, which is higher than the pre-merger estimate of $784 million. The report provides a description of the integration process within specific merger integration initiatives, along with projections of net merger savings.

Eversource Energy tracks regulatory compliance with merger requirements. The June 17, 2015 report lists 40 items in the categories of:

- Rates and Revenue Requirements – 15 items
- Accounting – five items
- Legal and Real estate – three items
- Energy Supply – three items
- Energy Efficiency – two items
- Strategy – two items
- Operations – four items
- Business Financial Services – three items
- Engineering – two items
- Corporate Relations – one item

Of these 40 items, 14 are relevant to CL&P. All of the CL&P relevant items were reported as complete or on schedule.

The Eversource CEO stated that the mission of the merger integration was to "simplify and standardize." Following are several anecdotes from the merger integration efforts that illustrate how the merger benefits have been achieved.

- At the point of merger, NU and NSTAR had 37 standard pole types. This has been reduced to six at Eversource.
- At the merger, CL&P had bad reliability and poor storm performance. Outage response was slowed by not having trouble technicians on the second shifts due to union resistance. This has been resolved in the interim with contractors and reliability has improved.
- Facilities are being consolidated and optimized. The "Work Center of the Future" is being implemented.
- Materials are being pre-staged and new emphasis is being placed on planning, scheduling, and executing work.
- The Eversource workforce strategy is evolving. NSTAR did more outsourcing in functions like Human Resources and Information Technology than NU and Eversource is identifying and implementing the better practice over time.
- The merger improved geographic diversity for both companies and facilitates storm response resource sharing.
- The CAO reports the merger was a "significant success." It has been well-received by Wall Street and it has achieved cost savings. Cost savings have already been considered in Connecticut rates. The effort is producing a "one company" climate with centers of excellence for consolidated functions. The capstone on the "one company" strategy is the name change to Eversource Energy.
- The merger improved geographic diversity for both companies and facilitates storm response resource sharing.

Additionally, Eversource is working to reduce O&M costs while improving service. Some of the techniques being used are:

- Increased use of technology, such as, electronic billing and remittance
- Separating distribution scheduled and emergency work
- Night loading of pre-kitted materials
- Improved work scheduling
- Outsourcing credit and collections and bill printing
- Outsourcing portions of Information Technology
- Moving retirees to health care exchanges
- Making the trouble technician first responders specialists

4. Eversource has a well-developed corporate performance management system.

Eversource describes its corporate performance management program (CPM) as follows:

> *Eversource has a strong performance-based culture. The performance goal-setting process at Eversource begins in the 4th quarter of the year, during the same time that the operating budgets are being developed for the upcoming year. The performance planning process, under the overall direction of the Chief Financial Officer and led by the Corporate Performance Management (CPM) group, is iterative, involving the Senior Team (the CEO and his direct reports), their officers, and other leaders to identify the key business initiatives and measures of performance that will be used to monitor and guide the company's work in the coming year. This process involves many inputs, including the company's strategic and financial planning, long range forecast, benchmarks and best practices, historical performance analysis, and regulatory or legal requirements.*
>
> *Key Initiatives are identified during the performance planning process to make further enhancements and improvements across the organizations. A small subset of the initiatives is identified by the Senior Team and called Priority Initiatives, which are shared across the Senior Team and address major focus areas of the business in the areas of financial growth, operational excellence & transformation, customer experience and workplace environment. Each key and priority initiative's major milestones are documented, with progress updated monthly in the Executive Performance Review.*
>
> *Key Performance Indicators are selected and aligned across Customer, Employee, Operational Excellence, and Financial & Regulatory dimensions to enable performance tracking against key processes throughout the coming year at the company and organization levels. Specific target levels of performance are determined for each key performance indicator (KPI). Target-setting is based on a combination of industry benchmarks, historical performance trends, operational budgets and specific plans for business performance in key areas.*

The Corporate Finance and Cash Management functions are headed by the Director, Corporate Finance and Cash Management, who, along with the Treasurer, serves as Eversource's primary liaison with the credit rating agencies. Ratings for CL&P and Eversource have improved since the NU/NSTAR merger which has had a positive effect on CL&P's borrowing costs. Commercial paper rates are 5% – 15% lower because of improved credit ratings. CL&P's recent bond issue ($300 million 30 year first mortgage bonds) was subscribed at 4.15%, a five to seven basis point savings over previous issues. An Intercompany Loan Agreement and a Credit Facilities Agreement govern CL&P's borrowing process.

The Investment Management work group manages a $4 billion pension fund, $2.5 billion 401(k) fund, two trusts with $800 million in assets, and the $25 million foundation trust.

The Claims and Insurance work group manages insurance risk and exposure and estimates insurance losses. Eversource uses some self-insurance and will compare themselves (benchmark) concerning the amount of coverage against other transmission and distribution companies. In addition to normal liability, insurance coverage includes privacy protection and terrorism. Generally, Eversource uses the lowest cost provider in the Transmission and Distribution (T&D) arena. Treasury works with Procurement concerning insurance requirements for their vendors.

The Enterprise Risk Management function is also the responsibility of the Treasurer and identifies and assesses risks, develops mitigation plans, manages mitigating efforts, and reports on risks and mitigation efforts to the Eversource CEO. Twice a year the Eversource Risk Committee reports on risk to senior management and the Finance Committee of the Board of Directors.

RATES

Eversource's Vice President, Rates and Regulatory Requirements reports directly to the Executive VP and CFO and is responsible for filing rate cases for eleven components of service for all of the Eversource regulated utilities, including CL&P. Rates filed include:

- Distribution
- Transmission (TAC)
- Non-bypassable Federally Mandated Congestion Charges (FMCC – Delivery)
- Generation Service Charge (GSC)
- Bypassable Federally Mandated Congestion Charges (FMCC – Generation)
- Competitive Transition Assessment (CTA)
- Conservation Adjustment Mechanism (CAM)
- Systems Benefits Charge (SBC)
- Revenue Decoupling Mechanism (RDM)
- Renewable Energy Investment Fund (Renewable)
- Conservation and Load Management (C&LM)

Filings for these rates are due at different times, with at least one rate filed every quarter. In addition to preparing the filings, this organization must participate in

The amount of effort or attention devoted to CL&P operations (as represented by the number of internal audits conducted) by the Eversource Internal Audit Department has remained steady over the past four years (average of 22). The number of internal audits that will be conducted in 2015 relevant to CL&P is estimated to be greater than, or comparable, to this average.

B. FINDINGS

1. The Treasury function operates effectively and efficiently.

The Treasury functions that support CL&P operations are located in Eversource Services corporate structure. Treasury functions are provided on a centralized basis for all of the Eversource companies, including CL&P. CL&P has benefited from this centralized Treasury structure and the close affiliation with the financial functions of the parent company. Credit ratings are very good, the highest in the electric utility sector, allowing Eversource to borrow funds, both short- and long-term, on favorable terms. The reasonable terms afforded Eversource have been passed down to CL&P through Eversource's internal borrowing program. Cash management for CL&P operations, including forecasting as well as day-to-day operations, have benefited by being a part of a larger consolidated cash function. The Treasury function is governed by clear and well documented policies and procedures and receives the proper visibility within the CL&P organization, as well as the parent organization and governing bodies.

2. CL&P's accounting process is cost effective and the organization is appropriately organized.

The Accounting organization is centralized, serving the parent organization and all of the affiliate companies, including CL&P. The merger of NU and NSTAR has allowed the number of accounting personnel to be reduced without adversely affecting service. Internal controls are established and reviewed on a periodic basis and have been effective. The relatively recent implementation of the Financial Standardization and Simplification Project has introduced standard and simplified processes and systems and allowed Eversource to streamline its accounting organization. New, planned systems (Payroll/HR and Supply Chain) should further enhance the effectiveness and efficiency of the accounting organization and provide cost and time savings to CL&P. Accounting functions are documented in the Accounting Policy Statements which reside on the Company intranet, allowing universal and instantaneous employee access.

3. Performance measurement trends of accounting transactions are not evaluated on a regular basis.

Performance measurements of some accounting transactions (payroll cost per FTE, cost per invoice, cost per work order, days to pay, etc.) are recorded, but trends are not recorded and compared over time. Although Eversource has participated in a benchmarking study concerning the cost of accounting transactions, the results of this study cannot be relied on because of the wide variance in the results and the inability to determine how and what costs were recorded by the benchmarking participants. Internal cost comparisons over time are not made.

4. The Budget functions are performed efficiently and effectively.

The financial forecasting, O&M and Capital budgeting, and cost control functions are performed in an efficient and effective manner. All of the functions normally associated with budgeting and variance analysis are located in a single organization that reports to the Eversource EVP and CFO. The forecasting and budgeting processes are supported by information systems and staffed with experienced personnel. The processes are well documented and receive appropriate exposure throughout the organization. Evaluations of proposed forecast and budgets are thorough as is the analysis of variances from initial forecasts and budgets. Finance personnel are embedded with operating units to assist in developing and analyzing budgets and providing information up the organization to the highest management levels. Financial planning, analysis, and reporting provide ample information to assist managers in the control of costs.

5. The tax function operates appropriately.

The tax function for CL&P is consolidated in the Eversource Tax Department. The tax personnel are sufficiently educated and experienced and are supported by the necessary software systems to provide efficient and cost effective service to Eversource's affiliates, including CL&P. The NU/NSTAR merger has allowed the Tax Department to reduce staff, while still maintaining the necessary service.

6. The Internal Audit function operates effectively and efficiently.

The Internal Audit department is staffed with experienced and qualified personnel. The audit process is complete, thorough, and based on risk-based criteria. The number of internal audits conducted on CL&P-relevant areas over the past five years was adequate for the circumstances and perceived risks. Follow-up on recommendations and action items is certain. The Eversource Internal Audit process recently received high marks on a quality assurance audit from a peer group (the Institute of Internal Auditors Quality Services, LLC).

7. The reporting relationship between Internal Audit and the Audit Committee is not clearly documented.

The VP, Internal Audit and Security or Chief Audit Officer (CAO) reports administratively to the Senior Vice President General Counsel and Corporate Secretary. Functionally, this position reports to the Chairman of the Audit Committee of the Board of Trustees. This reporting relationship is shown graphically in the latest Internal Audit Plan, but "the nature of the functional reporting relationship is not fully described in the audit charter" as required by the *International Standards for the Professional Practice of Internal Auditing* nor in organization charts produced by Human Resources.

8. Rates are developed in a timely and thorough manner.

Rates and Regulatory Requirements directs the financial and accounting data required for regulatory filings, designs appropriate rates and tariffs, and ensures compliance with the regulatory process. Costs that make up each of the items on customer bills are isolated by code block in the G/L and put into an Excel spreadsheet model that calculates the cost for the month. Analysts check each cost and calculation for reasonableness and compare the cost to the applicable revenue.

Perquisites

The Company provides executives with limited financial planning, health services, vehicle leasing, and access to tickets to sporting events, perquisites that it believes are consistent with peer companies. The current level of perquisites does not factor into decisions on total compensation.

DIRECTOR, BENEFITS AND HR OPERATIONS

The Director, Benefits and HR Operations is officed in Westwood and is responsible for several functions including benefits, disability and absence, workers compensation, fitness for duty, health and welfare plans, and the Human Resource Information System (HRIS).

Employee Benefits

The Eversource Director, Benefits and HR Operations has described the Eversource employee benefits program as follows:

> *Eversource employee benefits program has several key elements that are consistent with those offered by most major employers. These include comprehensive medical, dental, vision and prescription drug benefits that are designed to maintain the health of employees and their eligible dependents. In conjunction with health benefits, the Company also offers wellness programs to help manage and improve employee health, which in turn helps to moderate health benefit costs over time. The Company provides survivor benefits to help provide financial security for employees and their families in the event of accidental injury or death. These benefits are available in the form of life insurance and accident insurance. The Company provides illness and disability plans to provide income replacement for employees and their families who are unable to work due to illness or injury. The Company also sponsors retirement income and health programs to contribute to the future health and security of employees. These benefits are provided in the form of a defined contribution 401k plan and, for a closed group of employees, a defined benefit pension plan. Upon retirement, employees who meet certain age and service milestones are also eligible to participate in post-retirement medical plans.*

Our review confirms this description.

The 2012 merger of NSTAR and NU offered the opportunity for a number of cost savings. The most significant of these was the consolidation of the two company's employee benefits programs. Since the merger, HR has been focusing on consolidation of programs and standardization of practices.

Eversource "self-insures" its health insurance program. Under the self-funded plan design, the Company pays only the actual cost of healthcare claims, along with a fixed administrative fee for the insurance carrier covering the cost of administering the claim reimbursements to employees, managing the network of providers, and other costs of claim administration.

The Company offers three health insurance plans:

Workforce Strategy

Eversource IT utilizes a hybrid mix of employees and contractors. Employees manage all functions and are utilized for planning, new systems development, and critical core functions, such as, cybersecurity operations. Eversource IT outsources most routine work, such as, day-to-day applications enhancement, maintenance and support, the help desk, and operating the data centers.

In 2014, the IT staff was reduced in favor of contractors. The IT Director team, assisted by a consultant, Information Services Group (ISG), evaluated six proposal responses to a request for proposals. Tata Computer Services (TCS) won the contract to support the Customer Care function and Infosys has the contract to support all other IT functions. NSTAR had a similar contract with IBM for outsourced services before the merger, and Northeast Utilities (NU) had outsourced services with four other services companies in addition to relying on in-house employees. Eversource adopted a new services and support model which utilizes outsourcing for most routine IT tasks to help support the focus on strategy, policy, and critical applications systems after the NU/NSTAR merger.

The outsource contracts are governed by a common structure. The highest level of governance is the Executive Steering Committee, which is composed of the CIO and Infosys and TCS executives. The Executive Steering Committee holds a highly structured monthly meeting with Infosys and TCS. The next level is the Suppliers Steering Committee composed of the CIO's direct report Directors and equivalent representatives from Infosys and TCS. The working level is the Delivery Committee composed of IT managers and their contractor counterparts. The IT Infrastructure unit manages the Infosys and TCS contracts on a day-to-day basis.

The Infosys and TCS contracts are service level contracts, not staff augmentation capacity contracts. They are essentially unit price contracts. There is a base capacity of resource units like work stations and applications (not personnel) for all maintenance and a variable capacity of resource units for development. The contracts can be expanded or contracted. There is a base fixed charge for maintenance that can be changed over time as the number of resource units change. Both contracts have concurrent terms of five years with a commencement date of June 1, 2014. Both contracts have exit clauses and the governance terms are the same in both.

The outsource contracts specify use of industry standard Information Infrastructure Library (ITIL) processes and the IT Service Management (ITSM) tools. Eversource and the contractors utilize 19 ITIL processes. Training on the ITIL processes for Eversource personnel was provided by Infosys.

The contracts specify critical service levels and key measurements. Penalties can be assessed if standards are not being met.

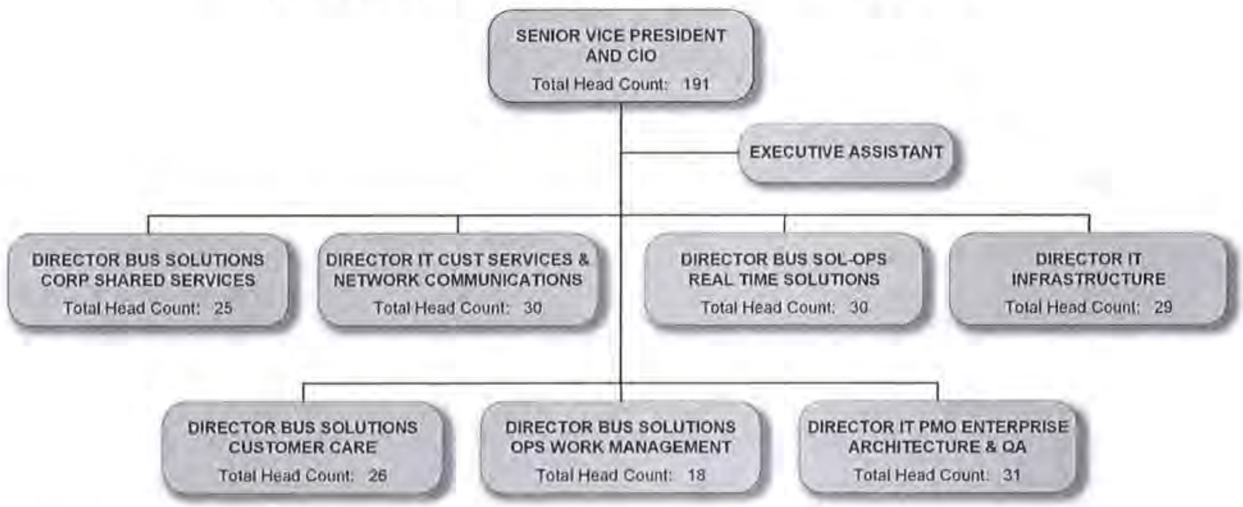
Eversource utilizes a consultant, ISG, to assist it in managing the Infosys and TCS contracts. ISG was the consultant which was instrumental in the outsourcing process and contracting. ISG provides an ongoing service to monitor the contractors' service levels and billing. ISG provides this service to other clients as well and has a web-based tool, Enlita, to facilitate the process. In addition, Eversource and the contractors have an arbitrator on retainer. To date, no issues have gone to arbitration since the inception of the contracts.

The Infosys contract has two components: a fixed fee for all maintenance work and a variable amount for enhancements. Approximately 60% of the Infosys applications development and maintenance work is done off-shore in India. The contract does require a minimum level of on-site support. A few of the Infosys on-site personnel are former Eversource or IBM employees. Infosys staffing for Eversource is approximately 40% in Berlin and 60% in India with a few contractors in Westwood. Infosys has a total of approximately 90 full time employees (FTE) dedicated to Eversource IT.

Organization Structure

The Information Technology organization structure is shown in the following table.

Information Technology Organization Structure



Organization Overview

The Information Technology (IT) group has seven units, each managed by a Director:

- Business Solutions for Corporate and Shared Services – supports applications for Human Resources, Supply Chain, and other support services
- Business Solutions for Operations Real Time applications – supports the supervisory control and data acquisition (SCADA) systems, outage management system (OMS), and other operations monitoring and control applications
- Business Solutions for Customer Care – supports the customer information systems and related applications
- Business Solutions for Operations Work Management – supports work management applications other than the real time applications
- IT Customer Services and Network Communications – provides end user computing and network switching and routing
- IT Infrastructure – manages the data centers, cybersecurity, and the major IT contractors
- IT Program Management Office – oversees the IT capital budget, major IT projects and the enterprise architecture and provides the quality assurance and testing functions

National Institute of Standards and Technology (NIST) framework and uses elements of the Electric Sector – Cybersecurity Capability Maturity Model (ES-C2M2) published by the Department of Energy and the Control Objectives for IT (COBIT) published by the Information Systems Audit and Control Association (ISACA).

The Corporate Information Security (CIS) services, policies, and standards apply to all Eversource business units and operating entities. Other corporate policies relevant to the definition and use of sensitive information include:

- Protection and Use of Company Assets and Resources Policy
- Records and Information Management Policy
- Code of Business Conduct
- Critical Infrastructure Protection Policy
- IT Vulnerability Management Policy
- IT Access Administration Policy
- Corporate Information Security Procedure

Critical Infrastructure Protection (CIP) asset information is defined by the North American Electric Reliability Corporation (NERC) standards. Eversource plans to combine the current two NU and NSTAR CIP programs when CIP version 5 is implemented by April 2016.

The Cybersecurity Plan includes the following elements:

- Risk Management
- Asset, Change, and Configuration Management
- Identity and Access Management
- Threat and Vulnerability Assessment
- Situational Awareness
- Information Sharing and Communications
- Event and Incident Response and Continuity of Operations
- Supply Chain and External Dependencies Management
- Workforce Management
- Cybersecurity Program Management

Eversource IT has adopted industry standard methodologies and tools to address the critical topic of cybersecurity.

3. **Eversource developed a thorough IT Merger Integration Roadmap and is executing it well.**

The IT Integration Roadmap for consolidating the NU and NSTAR systems and infrastructure was presented to the Senior Management Team on April 8, 2013. It included information on:

- The current state of IT systems
- The plan for 2013 key initiatives
- The plan for additional initiatives

A Technology Consolidation Plan was developed in March 2013. It is a five-year plan for consolidating and integrating business processes and solutions. The 2013 Five Year (2013–2017) Primary Initiatives were:

1. Consolidate HR systems into one core system
2. Consolidate Financial systems to one version of each core function: Plant, G/L, Budgeting, and Financial Statements
3. Implement enterprise OMS solution for all operating companies
4. Data Center consolidation
5. Integration of the company network
6. Migration to one email system and one voice network

The Technology Consolidation Plan was based on the following underlying beliefs and assumptions:

1. Consolidating systems is part of the corporate mission to become more efficient.
2. When consolidating systems, first consideration will be given to existing vendor solutions.
3. Consolidating systems still needs to be defined by business process redesign.
4. Enterprise solutions will be implemented where appropriate.
5. Consolidating systems will look at the entire application portfolio with the goal to reduce the portfolio in each area and in turn reduce the Total Cost of Ownership for the applications.

The IT organization has focused on implementing the Technology Consolidation Plan and is generally on target to complete it as planned.

4. IT has not yet reinstated long-term strategic planning.

There is no IT long-term strategic plan covering the period after 2017 when the Technology Consolidation Plan execution will be complete. The IT group is completely focused on completing the merger consolidation and integration plan at this point. While the merger integration plan was well-conceived and is being executed well, it is also far enough along that attention can be redirected to the next few years of IT development after 2017.

Exhibit No. ES-200

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Eversource Energy Service Company	**)**	**Docket No.**	**ER16-___-000**
Northeast Utilities Service Company	**)**	**Docket No.**	**ER03-1247-000**
ISO New England Inc. , *et al.*	**)**	**Docket Nos.**	**RT04-2-000**
	)		**ER04-116-000**
Bangor Hydro-Electric Company, *et al.*	**)**	**Docket No.**	**ER04-157-000**
NSTAR Electric Company	**)**	**Docket No.**	**EC06-126-000**
NSTAR Electric Company	**)**	**Docket No.**	**EL07-71-000**
NSTAR Electric Company	**)**	**Docket No.**	**ER07-549-000**
NSTAR, *et al.* and Northeast Utilities, *et al.*	**)**	**Docket No.**	**EC11-35-000**

PREPARED DIRECT TESTIMONY OF

LISA M. COOPER

ON BEHALF OF EVERSOURCE ENERGY SERVICE COMPANY

EXHIBITS TO DIRECT TESTIMONY OF LISA M. COOPER

Exhibit No.	Description
ES-201	Total Merger Costs Summary
ES-202	Transaction Costs - Bankers' Fees
ES-203	Transaction Costs - Lawyers' Fees
ES-204	Transaction Costs - Registration
ES-205	Transaction Costs - Consultants
ES-206	Regulatory Process Costs - Legal Fees
ES-207	Regulatory Process Costs - Registration S4
ES-208	Regulatory Process Costs - Consultants
ES-209	Non-Incremental Internal Labor Costs
ES-210	Separation Costs - Separation Program
ES-211	System Integration Costs
ES-212	Other Transition Costs
ES-213	Separation Costs - Separation Assistance
ES-214	Summary of Impact on CL&P’s, PSNH’s and WMECO’s PTF Revenue Requirements under Attachment F of ISO-NE OATT (1-year amortization)
ES-215	Summary of Impact on NSTAR Electric’s PTF Revenue Requirements under Attachment F of ISO-NE OATT (1-year amortization)
ES-216	Summary of Impact on NSTAR Electric SCADA Revenue Requirements under Schedule 1, Appendix A of the ISO-NE OATT (1-year amortization)
ES-217	Summary of Impact on Category A Revenue Requirements under Attachment ES-H, Schedule 21-ES to ISO-NE OATT (1-year amortization)
ES-218	Summary of Impact on Schedule 21-NSTAR’s Revenue Requirements under Attachment D to the ISO-NE OATT (1-year amortization)
ES-219	Summary of Impact on Category B Revenue Requirements under Attachment ES-I, Schedule 21-ES to ISO-NE OATT (1-year amortization)

ES-220	Calculation of Carrying Charges, Amortization and Unamortized balances
ES-221	Summary of Impact on CL&P's, PNSH's and WMECO's PTF Revenue Requirements under Attachment F of ISO-NE OATT (3-year amortization)
ES-222	Summary of Impact on NSTAR Electric's PTF Revenue Requirements under Attachment F of ISO-NE OATT (3-year amortization)
ES-223	Summary of Impact on NSTAR Electric SCADA Revenue Requirements under Schedule 1, Appendix A of the ISO-NE OATT (3-year amortization)
ES-224	Summary of Impact on Category A Revenue Requirements under Attachment ES-H, Schedule 21-ES to ISO-NE OATT (3-year amortization)
ES-225	Summary of Impact on Schedule 21-NSTAR's Revenue Requirements under Attachment D to the ISO-NE OATT (3-year amortization)
ES-226	Summary of Impact on Category B Revenue Requirements under Attachment ES-I, Schedule 21-ES to ISO-NE OATT (3-year amortization)

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Eversource Energy Service Company	**)**	**Docket No.**	**ER16-___-000**
Northeast Utilities Service Company	**)**	**Docket No.**	**ER03-1247-000**
ISO New England Inc. , ***et al.***	**)**	**Docket Nos.**	**RT04-2-000**
	)		**ER04-116-000**
Bangor Hydro-Electric Company, ***et al.***	**)**	**Docket No.**	**ER04-157-000**
NSTAR Electric Company	**)**	**Docket No.**	**EC06-126-000**
NSTAR Electric Company	**)**	**Docket No.**	**EL07-71-000**
NSTAR Electric Company	**)**	**Docket No.**	**ER07-549-000**
NSTAR, ***et al.*** **and Northeast Utilities,** ***et al.***	**)**	**Docket No.**	**EC11-35-000**

PREPARED DIRECT TESTIMONY
OF LISA M. COOPER
ON BEHALF OF EVERSOURCE ENERGY SERVICE COMPANY

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A1. My name is Lisa M. Cooper. My business address is 107 Selden Street, Berlin, Connecticut 06037.

Q2. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A2. I am employed by Eversource Energy Service Company ("Eversource Service") as the Director of Transmission Rates and Revenue Requirements.

Eversource Service provides centralized services to Eversource Energy and the Eversource Companies.[1]

Q3. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A3. I graduated from the University of Connecticut with a Bachelor of Science degree in Accounting in 1983 and am a Certified Public Accountant. Prior to my employment at Eversource Energy, I was a manager at Haggett, Longobardi and Company (merged with CohnReznick). I joined Eversource Energy in 1990 and served in a number of regulatory, financial, accounting and transmission business positions. I was the Manager of Transmission Rates from June 2007 until October 2013. In 2013, I assumed my current position, as Director of Transmission Rates and Revenue Requirements. My current responsibilities include the coordination and implementation of transmission revenue requirements and rates for the Eversource Companies. I have overall responsibility for regulatory interfaces associated with all transmission rate related filings before Eversource Energy's three state utility commissions, as well as the Federal Energy Regulatory Commission

[1] Eversource" or "Eversource Energy" refer to the current merged company and all of its operating utility subsidiaries (The Connecticut Light and Power Company ("CL&P"), Public Service Company of New Hampshire ("PSNH"), Western Massachusetts Electric Company ("WMECO"), Yankee Gas Services Company ("Yankee Gas"), NSTAR Electric Company ("NSTAR Electric") and NSTAR Gas Company ("NSTAR Gas")). "Eversource Companies" refers to NSTAR Electric, CL&P, WMECO and PSNH.

("FERC" or the "Commission"). I have directed the preparation and filing of various documents and exhibits related to transmission revenue requirements, rates and projects. I have testified before the Connecticut Public Utilities Regulatory Authority and the Massachusetts Department of Public Utilities. I have also submitted testimony to the Commission and provided technical presentations before the Commission Staff.

Q4. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A4. The purpose of my testimony is to describe the costs that Eversource incurred in connection with the 2012 merger. I also describe the transmission tariff revisions and cost recovery mechanism that the Eversource Companies are proposing in this proceeding in order to recover these transmission merger-related costs. In addition, I am sponsoring the calculation of the revenue impact of the Eversource Companies' proposal.

Q5. ARE YOU SPONSORING ANY EXHIBITS?

A5. Yes, in addition to my testimony, I am sponsoring Exhibit Nos. ES-201 through ES-226.

II. BACKGROUND AND SUMMARY OF PROPOSAL

Q6. PLEASE DESCRIBE THE EVERSOURCE COMPANIES' RATES THAT WOULD BE AFFECTED BY THIS FILING.

A6. The Eversource Companies recover their total transmission revenue requirements through a combination of regional and local rates, both of which are part of Section II Open Access Transmission Tariff ("OATT") of the ISO New England Inc. ("ISO-NE") Transmission, Markets and Services Tariff ("ISO-NE OATT"). The majority of the costs associated with the regional Pool Transmission Facilities ("PTF") are recovered through Regional Network Service ("RNS") rates. Those rates are calculated under a formula rate included as Attachment F to the ISO-NE OATT. Any NSTAR Electric PTF costs not recovered under RNS rates, as well as the cost of non-PTF, are recovered under Schedule 21-NSTAR of the ISO-NE OATT. Any CL&P, PSNH and WMECO PTF costs not recovered under RNS rates, as well as the cost of non-PTF, are recovered under Schedule 21-ES[2] of the ISO-NE OATT. These Schedules contain formula rates that calculate NSTAR Electric's (Schedule 21-NSTAR, Attachments D and F) and CL&P's, PSNH's and WMECO's (Schedule 21-ES, Attachments ES-H and ES-I) transmission revenue requirements. The revenues that the Eversource Companies receive

[2] This Schedule was previously designated as Schedule 21-NU; a filing changing the name of this schedule to Schedule 21-ES was accepted by the Commission in Docket No. ER16-348 on December 22, 2015.

under the RNS rate are a revenue credit to the Eversource Companies' Schedules 21-NSTAR and 21-ES. I will refer to the formula rates in ISO-NE OATT Attachment F, Schedules 21-NSTAR Attachments D and F, and Schedule 21-ES Attachments ES-H and ES-I as the "Transmission Service Formula Rates." All of these rates are affected by this filing. In addition to recovering their transmission revenue requirements, NSTAR Electric and CL&P recover their costs for providing Scheduling, System Control and Dispatch Service under ISO-NE OATT Schedule 1, Appendices A (NSTAR Electric) and C (CL&P). The rates in ISO-NE OATT Schedule 1, Appendix A are also affected by this filing.[3]

Q7. ARE THE MERGER-RELATED COSTS INCLUDIBLE IN THE TRANSMISSION SERVICE FORMULA RATES AND ISO-NE OATT SCHEDULE 1 APPENDIX A RATES?

A7. Yes. All of the transmission merger-related costs that Eversource incurred and is requesting recovery of are Administrative and General ("A&G") expenses, recordable to A&G FERC Accounts Nos. 920, 921, 923, 926, 928 and 930.2. All of these accounts are included in the Transmission Service Formula Rates and ISO-NE OATT Schedule 1 Appendix A rates. As a result, all of the Eversource Companies' transmission merger-related costs would

[3] Appendix C is not affected because it does not include Administrative & General ("A&G") expenses. As will be explained further in my testimony, this filing pertains to the recovery of A&G expenses, and Appendix C does not include an A&G component.

have been included in the Transmission Service Formula Rates and ISO-NE OATT Schedule 1 Appendix A rates but for Eversource's hold harmless commitment to the Commission. For example, Eversource's transmission merger-related external legal expenses would have been recorded to A&G FERC Account No. 923, Outside Services Employed (an account included in the Transmission Service Formula Rates and ISO-NE OATT Schedule 1 Appendix A rates), but for Eversource's hold harmless commitment.[4]

Q8. ARE THE EVERSOURCE COMPANIES PROPOSING TO INCLUDE THE TRANSMISSION MERGER-RELATED COSTS IN THE TRANSMISSION SERVICE FORMULA RATES AND ISO-NE OATT SCHEDULE 1 APPENDIX A RATES AT THIS TIME?

A8. The Eversource Companies propose to include the portion of the merger-related costs that are functionalized to transmission ("Transmission Merger-Related Costs") in their Transmission Service Formula Rates commencing June 1, 2016. I explain later in my testimony how Eversource determined which portion of the merger-related costs should be functionalized to transmission. The Eversource Companies propose to amortize these costs over a one-year period. If this requested amortization period is granted, the Eversource Companies will waive the recovery of carrying charges on the

[4] Certain of these expenses were recorded to FERC Account No. 426.5 due to the hold harmless commitment, but absent that commitment would have been recorded to A&G accounts.

Transmission Merger-Related Costs from the time they were incurred through May 31, 2016, and will waive the inclusion of the unamortized balance of such costs in transmission rate base commencing June 1, 2016. I will refer to this proposal as the Eversource Companies' "Proposed Cost Recovery Mechanism." In the alternative, if the Commission does not grant the Eversource Companies' request to amortize these costs over a one-year period, the Eversource Companies propose that the costs be amortized over a three-year period, that carrying costs on the Transmission Merger-Related Costs be added to the Transmission Merger-Related Costs until the amortization begins, and that the unamortized balance of such costs be included in rate base commencing June 1, 2016. I will refer to this proposal as the Eversource Companies' "Alternative Cost Recovery Mechanism."

III. MERGER-RELATED COSTS

A. Introduction

Q9. HOW DID EVERSOURCE IDENTIFY AND ANALYZE MERGER-RELATED COSTS?

A9. Before the merger between Northeast Utilities and NSTAR was consummated, Legacy NU and Legacy NSTAR performed a Net Benefits Analysis that estimated the costs that the Eversource Companies would incur in connection with the merger.[5] The cost projections in that analysis were derived primarily on the basis of past experience with a previous merger of NSTAR. *See* Vaughan Testimony, Exhibit No. ES-100 at Section IV.A. Following the consummation of the Northeast Utilities and NSTAR merger, CL&P prepared a Merger Integration Report that calculated the actual merger-related costs and benefits through December 31, 2013, and projected savings for the years 2014 through 2022. *See* Exhibit No. ES-101 and discussion in Ms. Vaughan's testimony, Exhibit No. ES-100. The Merger Integration Report provided actual costs by functional area consistent with the Net Benefits Analysis. The Merger Integration Report has since been updated, and now calculates cost savings through September 30, 2015. *See* Exhibit No. ES-103, attached to Ms. Vaughan's testimony. My testimony in this proceeding is based on that most recent Merger Integration Report.

Q10. PLEASE DESCRIBE THE MERGER-RELATED COSTS THAT EVERSOURCE INCURRED.

A10. The merger-related costs are comprised of transaction costs (i.e., legal, banking and other costs incurred to evaluate, structure and close the transaction); and transition costs (i.e., costs necessarily incurred to achieve synergies from the merger). The categories of transaction and transition costs

[5] "Northeast Utilities" and "NSTAR" refer to the pre-merger holding companies. "Legacy NU" refers to Northeast Utilities and all of its subsidiaries prior to the merger. "Legacy NSTAR" refers to NSTAR and all of its subsidiaries prior to the merger.

discussed below are the same as those presented in the Merger Integration Reports in the proceedings before the Connecticut Public Utility Regulatory Authority ("CT PURA") (Docket No. 14-05-06) and the Massachusetts Department of Public Utilities ("MA DPU") (Docket No. 14-150) requesting recovery of, respectively, CL&P's electric distribution and NSTAR Gas's gas distribution merger-related costs. In those proceedings, the CT PURA approved CL&P's recovery of distribution merger-related costs in retail electric rates in Connecticut, and the MA DPU approved NSTAR Gas's recovery of gas merger-related costs in retail gas service rates in Massachusetts. Ms. Vaughan discusses those proceedings in more detail; see Exhibit No. ES-100. I discuss specific transaction and transition costs below.

Q11. IF CERTAIN EVERSOURCE COMPANIES ARE ALREADY RECOVERING MERGER-RELATED COSTS IN CONNECTICUT AND MASSACHUSETTS, HOW DID EVERSOURCE ENSURE THAT THOSE MERGER-RELATED COSTS ARE NOT ALSO RECOVERED IN THIS FILING?

A11. The Eversource Companies are not recovering the same portion of merger-related costs from retail customers in Connecticut and Massachusetts. In the proceedings before the Connecticut and Massachusetts state regulatory commissions, Eversource did not seek, nor did it obtain, recovery of any of the portion of Eversource's transmission merger-related costs that are subject to FERC jurisdiction. In Connecticut, only the portion of CL&P's distribution merger-related costs that were subject to the CT PURA's jurisdiction were allowed recovery, and in Massachusetts only the portion of NSTAR Gas's distribution merger-related costs that were subject to the MA DPU's jurisdiction were allowed recovery. Eversource used the same plant allocation factors to functionalize transmission merger-related costs that were used in the CL&P distribution and NSTAR Gas proceedings. As a result, there is no over or under recovery of merger-related costs nor a double-recovery of the same costs.

Q12. PLEASE EXPLAIN THE PROCEDURES AND PROCESSES USED BY EVERSOURCE TO TRACK MERGER-RELATED COSTS.

A12. In accordance with its hold harmless commitment to the Commission, Eversource instituted controls to segregate merger-related costs so that they could be both tracked and excluded from the customers' rates. Prior to the consummation of the merger on April 10, 2012, merger-related incremental costs (both transaction merger-related costs and transition merger-related costs) for Legacy NU were recorded to the Legacy NU parent company books. Legacy NU used a separate activity code, "ODEDT," to identify and track merger-related costs. The Legacy NU Accounting Department monitored these costs to ensure they were appropriately recorded. Incremental transaction merger-related costs for Legacy NSTAR were recorded to the Legacy NSTAR parent company books while incremental transition merger-related costs were recorded to Legacy NSTAR Electric's books.[6] Legacy NSTAR used a unique subaccount (subaccount 39) to identify and track merger-related costs. The Legacy NSTAR Accounting Department monitored these costs to ensure they were appropriately recorded.

In addition, in early 2011, Legacy NU and Legacy NSTAR worked with [redacted], a leading global management consulting firm with specialized expertise in organization transformation, to prepare for Day 1 readiness and integration planning for the merged company. This process included documenting the business functions at Legacy NU and Legacy NSTAR. Functional Integration Teams ("FIT") were established and subject matter experts identified at each company. Legacy NU and Legacy NSTAR provided FIT members detailed guidance on how to track merger-related costs. As indicated above, Legacy NU used a separate activity code, "ODEDT," and Legacy NSTAR used a unique subaccount (subaccount 39) to identify and track merger-related costs. Post-merger, all incremental merger-

[6] "Legacy NSTAR Electric" refers to NSTAR Electric prior to the merger. Similarly, "Legacy NU Companies" refers to CL&P, PSNH and WMECO prior to the merger. "Legacy Companies" refers collectively to the Legacy NU Companies and Legacy NSTAR Electric.

related costs were recorded to the Legacy NU parent company books and monitored by the Accounting Department to ensure they were appropriately recorded. In 2014, Eversource Service implemented a new accounting system that established similar activities as described above to identify and track remaining merger-related transition costs. Later in my testimony I discuss non-incremental internal labor costs for which Eversource is requesting recovery in this filing.

Q13. PLEASE PROVIDE A SUMMARY OF THE MERGER-RELATED COSTS.

A13. On an enterprise-wide basis, Eversource incurred $68 million in incremental transaction costs and $56.4 million in incremental transition costs for which it is seeking recovery of the transmission-related portion in this filing. As I explained earlier in my testimony, all of these costs are A&G expenses, and would have been included in the Eversource Companies' formula rates but for the Eversource Companies' hold harmless commitment. As shown in the Table below, these costs fall into several categories:

Table A: Incremental Merger-Related Costs

Cost Category	Enterprise-Wide Costs through Sept. 30, 2015 ($ Millions)[7]	Exhibit No.
Incremental Transaction Costs		
Bankers' Fees	$48.0	ES-202
Lawyers' Fees	$11.7	ES-203
Registration Fees	$2.1	ES-204
Consultants Fees	$1.4	ES-205
Regulatory Process Costs	$4.7	ES-206, ES-207, ES-208
Total Incremental Transaction Costs:	$68.0	
Incremental Transition Costs		
Separation Program Costs	$32.5	ES-210
System Integration Costs	$13.3	ES-211
Other Transition Costs	$10.5	ES-212
Separation Assistance Costs	$0.2	ES-213
Total Incremental Transition Costs:	$56.4	
Total Incremental Transaction and Transition Costs	$124.4	ES-201

The transmission-related portion of these incremental costs is $36 million. *See* Exhibit No. ES-201. In addition to these incremental costs, the Eversource Companies also incurred non-incremental transmission-related

[7] *See* Exhibit No. ES-201 for a detailed chart of merger-related costs. Numbers in the above table may not match the totals due to rounding.

internal labor costs of $1.4 million. Thus, the total transmission-related costs are $37.4 million.

Q14. DOES THE ABOVE TABLE INCLUDE ALL OF EVERSOURCE'S MERGER-RELATED COSTS?

A14. No. Eversource is only seeking to recover a portion of its merger-related costs. Specifically, Eversource is foregoing recovery of executive severance and retention costs, goodwill and branding costs.

B. Transaction Costs

Q15. EXPLAIN THE TRANSACTION COSTS THAT EVERSOURCE IDENTIFIED.

A15. As shown in the above Table, transaction costs includes costs in the following categories: bankers' fees, lawyers' fees, costs to register the new company, consulting costs for the transaction, and regulatory process costs (which include legal fees and consultants costs stemming from the regulatory process). As explained earlier, I will also discuss internal labor costs as part of this category.

1. Bankers' Fees

Q16. PLEASE DESCRIBE THE BANKERS' FEES.

A16. Bankers' fees included the services of [redacted] Exhibit No. ES-202 demonstrates the yearly bankers' fees incurred for each of these companies, and shows the total bankers' fees incurred were $48.0 million between 2010 and 2012.

Q17. WHAT SERVICES DID THESE COMPANIES PERFORM?

A17. The services provided by the companies identified above are as follows:

- [redacted] Provided Legacy NU with financial advisory services for the transaction, which included services to determine whether the terms of the merger were fair (a Fairness Opinion). Also, it provided general business and financial analyses of Legacy NU and Legacy NSTAR, including a transaction feasibility analysis and pricing of the transaction. In addition, it acted as a dealer-manager in the exchange offer, and assisted in corporate capital planning and risk management for the transaction.
- [redacted] Acted as the investment banker for Legacy NU, providing analysis on the business and financial condition of Legacy NU and Legacy NSTAR. [redacted] formulated a negotiation strategy and aided in the consummation of the transaction. It also provided advice regarding various capital markets alternatives and provided other customary investment banking services throughout the contract.

- [redacted] Provided Legacy NSTAR with financial advisory services and assistance in connection with the merger. Such services included performing financial analyses, issuing a fairness opinion and formulating a negotiation strategy for the financial aspects of the transaction.
- [redacted] Provided Legacy NSTAR with financial services in connection with a possible sale of all or a majority of the stock of Legacy NSTAR in any merger. In addition, it performed financial analyses, issuing a fairness opinion and formulating a negotiation strategy for the financial aspects of the transaction.

2. Lawyers' Fees

Q18. WITHOUT DIVULGING PRIVILEGED INFORMATION, PLEASE DESCRIBE THE TRANSACTION LAWYERS' FEES.

A18. As detailed in Exhibit No. ES-203, Eversource incurred fees for legal and associated services provided in connection with the merger transaction. The services were primarily provided by: [redacted] These firms and entities advised Eversource with respect to the merger and the preparation of merger-related documents.

As demonstrated in that exhibit, total legal and associated fees incurred from 2010-2012 were $11.7 million.

3. Registration Fees

Q19. PLEASE DESCRIBE REGISTRATION FEES.

A19. As shown in Exhibit No. ES-204, Eversource paid [redacted] in order to register the new company. The total fees incurred from 2010-2011 were $2.1 million.

Q20. PLEASE DESCRIBE THE SERVICES EACH FIRM PERFORMED.

A20. The services provided by the companies identified above are as follows:

- [redacted] Assisted in the conversion of registration and other documents to the SEC Electronic Data Gathering, Analysis, and Retrieval ("EDGAR") system format. In addition, [redacted] assisted in the set-up, assembly, submission, confirmation and acceptance of necessary SEC documents. [redacted] also printed proxy statements.
- [redacted] Assisted in holding special stockholder meetings for Legacy NSTAR, including the management of printing and delivery of shareholder letters, proxy materials and annual reports.

- [redacted] Assisted in providing professional advice on issuing the proxy solicitation regarding the special meeting held related to the merger.
- [redacted] Assisted in holding special stockholder meetings for Legacy NU, including the management of printing and delivery of shareholder letters, proxy materials and annual reports.
- [redacted] Assisted with Legacy NSTAR's special shareholder meetings and proxy solicitations, including mailing and processing letters and telephone solicitation campaigns. This firm also assisted in the research and retrieval of voting information.
- [redacted] Acted as the stock transfer agent.
- [redacted] Assisted with Legacy NU's special shareholder meetings and proxy solicitations, including mailing and processing letters and telephone solicitation campaigns.

4. Consultant Fees

Q21. PLEASE DISCUSS THE CONSULTANT FEES.

A21. As detailed in Exhibit No. ES-205, Eversource used the services of [redacted] for consulting services for the transaction in 2010 and 2011. As demonstrated in that exhibit, the total consultants' costs were $1.4 million.

Q22. PLEASE DESCRIBE THE CONSULTING SERVICES PERFORMED.

A22. The companies identified above provided the following services:

- [redacted] Retained by Legacy NU to examine preliminary purchase accounting issues and review high level tax and accounting considerations.
- [redacted] Engaged to provide public and investor relations services in connection with the merger.
- [redacted] Engaged to review audit working papers of Legacy NU's independent auditors associated with financial statements. In addition, [redacted] provided services associated with the analysis of tax and accounting issues arising from the proposed transaction.

5. Regulatory Process Costs

Q23. PLEASE DISCUSS THE REGULATORY PROCESS COSTS.

A23. As detailed in Exhibit Nos. ES-206 through ES-208, Eversource incurred regulatory process costs for legal fees, SEC S-4 registration, and consultants. As shown in Exhibit No. ES-206, Eversource incurred legal fees totaling $4.4 million for professional services provided in 2010-2011 in connection with the regulatory process for the merger. As shown in Exhibit No. ES-207, Eversource incurred total fees for S-4 registration of $.04 million. These S-4 registration fees were costs for registering with the Securities and Exchange Commission under the Securities Act of 1933. Finally, as shown in Exhibit No. ES-208, Eversource incurred $0.2 million in fees for consultant services related to the merger proceedings.

6. Non-Incremental Internal Labor Costs

Q24. PLEASE DESCRIBE THE NON-INCREMENTAL INTERNAL LABOR COSTS INCURRED.

A24. Legacy NU and Legacy NSTAR originally included non-incremental internal labor costs that were recorded on their transmission owning operating companies' books in activity "ODEDT" and subaccount 39, respectively, and they were therefore included in their formula rates. This was based on their view that the hold harmless commitment did not apply to non-incremental transition costs (i.e. salaries for employees that would be the same whether or not those employees were involved in merger-related activities). However, as a result of the Commission's audit of NSTAR Electric's 2011 formula rate charges in Docket No. FA12-10-000, Legacy NSTAR Electric refunded to transmission customers approximately $0.4 million of non-incremental internal labor recorded to subaccount 39. The Legacy NU Companies followed this same process and refunded to transmission customers approximately $1.0 million of non-incremental internal labor costs that had been recorded to activity ODEDT. All of the non-incremental internal labor costs that were removed from the formula rates and refunded to customers are included in the transmission merger-related costs for which Eversource seeks recovery in this proceeding. These costs are additional to the merger-related costs that Eversource identified in the Merger Integration Report. Non-incremental internal labor merger-related costs are identified in Exhibit No. ES-209.

C. Transition Costs

Q25. PLEASE EXPLAIN THE TRANSITION COSTS.

A25. Transition costs are classified into the following categories: separation program costs, separation assistance costs, system integration costs, other transition costs, and estimated future costs. Transition costs total $56.4 million enterprise-wide. *See* Exhibit No. ES-201 and Section III.C.5. herein.

Q26. HOW DID EVERSOURCE IDENTIFY AND TRACK TRANSITION COSTS?

A26. In order to implement the merger, Merger Integration Team ("MIT") managers and the Integration Planning Management Organization ("IPMO") evaluated the initiatives that were needed to integrate the various functions of

Legacy NSTAR and Legacy NU. *See also* Vaughan Testimony, Exhibit No. ES-100, at Section IV.A. (discussing Eversource's organization of activities along functional lines); Exhibit No. ES-121 at 40 (Sage Audit Report discussing the Eversource "functionally-centralized organization structure"). If management determined that the initiatives and their costs were merger-related, the accounting tracking processes I describe in Section III.A. above would be applied. As detailed below, the transition costs that were incurred are all merger-related and needed for Eversource to develop common platforms for efficient post-merger operation and integration of its management and work processes.

1. Separation Program Costs

Q27. PLEASE DISCUSS THE SEPARATION PROGRAM COSTS INCURRED.

A27. The separation program costs include severance costs detailed in Exhibit No. ES-210. Total separation program costs are $32.5 million and apply to non-executive severance (Eversource is not seeking recovery for executive severance costs). The costs are comprised primarily of conventional severance payments based on years of service, outplacement costs, and COBRA/medical costs.

2. System Integration Costs

Q28. PLEASE DISCUSS THE SYSTEM INTEGRATION COSTS INCURRED.

A28. In order for Eversource to operate efficiently following the merger, Eversource developed common platforms and other systems for numerous activities within the merged company. To address these issues, Eversource hired various companies to provide services related to the following system integration initiatives: Lotus Notes Email Integration; Desktop Strategy; Information Technology ("IT") Requirements/Monthly Integration Costs; United Security Architecture; Claims Management System Integrations; Arrears Forgiveness Program Standardization; HRIS/Recruiting Application; Process Change & Integration; Customer Digital Business Roadmap; NSTAR Electric/WMECO Energy Efficiency ("EE") Data Consolidation; Transportation System Consolidation; and Cascade Project. As shown in Exhibit No. ES-211 these initiatives resulted in total costs of $13.3 million.

Q29. WHAT DID THESE SYSTEM INTEGRATION INITIATIVES ENTAIL?

A29. The system integration initiatives involved the following:

- Lotus Notes Email Integration: This initiative involved integrating two separate email systems into a consolidated platform. The separate Legacy NU and Legacy NSTAR email systems caused compatibility and calendaring issues. This integration effort required outside IT labor obtained from [redacted] to provide training to employees and convert the Legacy systems to the current Lotus Notes platform.

- Desktop Strategy: This initiative allowed all employees to share applications and business processes across the merged organization. This was considered a prerequisite for business process redesigns. This integration effort required outside IT labor obtained from [redacted]
- IT Technology Requirements/Monthly Integration Costs: This initiative implemented a new IT organization, infrastructure and application support strategy. This new strategic sourcing initiative brought together the Legacy NU and the Legacy NSTAR IT organizations. In addition, the outside support contracts were assessed to develop a single organization that enabled IT to become more efficient and effective. Training and travel were required to complete this IT transitional effort and move to a steady state and contract commencement.
- United Security Architecture: This initiative integrated and consolidated all employees into one firewall management console

and remote access program under a central management umbrella. [redacted] was hired to migrate Legacy NSTAR systems onto Legacy NU systems and provide audit preparation support.

- Arrears Forgiveness Program Standardization: This initiative involved the Massachusetts Arrearage Management Program ("AMP"), which helps qualified limited-income WMECO and NSTAR Electric customers resolve delinquent balances, maintain utility service, and better manage their monthly payments. The Arrears Forgiveness Program Standardization initiative focused on identifying key best practice processes and procedures within both WMECO and NSTAR Electric's AMP programs and resulted in implementing associated enhancements to align the programs. This enhancement and alignment process streamlined program operations and ensured that the individual AMP programs provided optimal benefits to limited-income customers in Massachusetts. This initiative required outside IT labor obtained from contractors [redacted], Tata Consultancy Services and Infosys.
- Claims Management System Integrations: This initiative consolidated the claims management systems of Legacy NU and Legacy NSTAR into one process and application, which provided the

ability to leverage combined reporting on claims. This initiative required hiring outside services from [redacted]

- HRIS/Recruiting Application: This initiative entailed reviewing Human Resource business practices to determine how they performed and the level of information needed to address new improved practices for the merged organization. This initiative required hiring professional consulting services from [redacted] and outside IT labor obtained from [redacted] The outside labor and consulting services allowed Eversource to reduce license fees and create efficiencies as a result of the consolidated business practices.
- Process Change & Integration: This initiative required professional services to evaluate replacing or upgrading general ledger and budgeting systems. Professional services were obtained from [redacted] The new systems allowed for consistency and improved comparability, which reduced IT support and data inputs.
- Customer Digital Business Roadmap: This initiative standardized the six individual Eversource operating companies' external websites. The objective was to provide consistency across all the websites, to

improve customer service by adding additional self-service features. This initiative required hiring professional services from [redacted] and labor from [redacted] The consistent website design reduces development and maintenance costs.

- NSTAR Electric/WMECO Energy Efficiency ("EE") Data Consolidation: NSTAR Electric and WMECO integrated their respective EE tracking systems to obtain a single, unified statewide tracking approach for their EE programs. Eversource migrated WMECO's programs into NSTAR's Electric's tracking system, eTRAC, in a phased approach throughout the year. These consolidation costs ultimately lead to customer benefits through reduced IT costs for a single database tracking system, and reduced regulatory and legal service costs associated with the unified approach. This initiative required hiring professional consulting services from [redacted] to obtain eTRAC Tier 2 Support.
- Transportation System Consolidation: This initiative integrated and consolidated all employees onto one Transportation Fleet Management System. This integration effort required outside IT labor obtained from [redacted]

- Cascade Project: This initiative integrated the Eversource Companies onto the Cascade System to be in compliance with North American Electric Reliability Corporations ("NERC") Critical Infrastructure Protection ("CIP") Number 5. This system is used for facilitating maintenance on assets that support the electric network, with the goal of increasing reliability and system resiliency. At the same time it also helps lower overall maintenance costs, reduces potential environmental hazards and increases employee and public safety. This integration effort included a workshop conducted by [redacted] to assess the feasibility of adding NSTAR Electric into the Legacy NU system.

3. Other Transition Costs

Q30. PLEASE DISCUSS THE OTHER TRANSITION COSTS INCURRED.

A30. Eversource hired various companies to provide services related to the following transition initiatives: Operational Review of Facilities and Warehouse, Legal E-Billing Solutions, Dissolve NSTAR LLC, Enterprise Call Center Technology, Supervisory control and data acquisition ("SCADA")/ Transmission Supervisory control and data acquisition ("TSCADA"), and Supply Chain System Consolidation. In addition, legal costs were incurred for professional services related to implementing these initiatives. As detailed in Exhibit No. ES-212, Eversource incurred services totaling $10.5 million in other transition costs.

Q31. WHAT DID THESE OTHER TRANSITION INITIATIVES ENTAIL?

A31. The other transition initiatives involved the following:

- Dissolve NSTAR LLC. As a result of the merger, the NSTAR holding company and all of the NSTAR subsidiaries were merged into the Northeast Utilities parent holding company system through a two-step process described in the Agreement and Plan of Merger, as amended, that was included in the application to the Commission in Docket No. EC11-35-000. Subsequent to the merger, the subsidiary NSTAR LLC, created for purposes of accomplishing the merger, was dissolved. In addition, NSTAR Electric & Gas Corp., Legacy NSTAR's service company, was merged into Northeast Utilities Service Company[8] (among other changes). These changes in corporate structure necessitated significant changes in Hyperion Financial Management ("HFM") to properly reflect the corporate structure for financial reporting. The HFM hierarchies needed to be modified to reflect this new corporate structure. This initiative primarily required hiring

[8] On July 1, 2015, Northeast Utilities Service Company's legal name was changed to Eversource Energy Service Company.

professional consulting services. In addition, this initiative required outside IT labor obtained from [redacted]

- Enterprise Call Center Technology project was an initiative to consolidate the current disparate systems and provide a single Enterprise call center suite of applications across the Legacy NU and Legacy NSTAR Call Centers. The call centers needed the ability to answer callers in a virtual center across geographically diverse locations with consolidated management, reporting and business continuity and disaster recovery plans. This integration effort primarily required outside IT labor obtained from [redacted]
- Operational Review of Facilities and Warehouses was an initiative to review the buildings owned and/or occupied by the Eversource Companies to determine if synergies would be obtained by consolidation. This initiative required hiring professional consulting services from [redacted] In addition, this initiative required outside IT labor obtained from [redacted]
- Legal E-Billing Solution was an initiative to evaluate two separate E-billing systems to determine the best system going forward. This resulted in the implementation and conversion of data held in Legacy

NU's legal billing system into the Serengeti Legal Tracker. This consolidation streamlined data collection and review and invoice processing. This initiative required the contracting of internet-based services with [redacted]

- SCADA/TSCADA was part of the Enterprise Energy Control System Project, which was an initiative to replace the existing Electrical Distribution and Transmission SCADA, Energy Management System and Distribution Automation technologies with a single platform system. In addition, this initiative was necessary for the success of other initiatives such as the Operations Organization Standardization, Transmission Control Center Consolidation, Information Technology Application Portfolio Rationalization, and Information Technology Data Center Consolidation. This initiative primarily required hiring professional consulting services from [redacted]
- Supply Chain System Consolidation was an initiative to evaluate two separate supply chains to identify differences and key integration points which allowed for the selection and implementation of a new supply chain. This integration effort primarily required outside IT labor obtained from [redacted]

4. Separation Assistance Costs

Q32. PLEASE EXPLAIN THE SEPARATION ASSISTANCE COSTS.

A32. Separation assistance includes services provided by [redacted] a company hired to provide employees with outplacement and career transition services. As shown in Exhibit No. ES-213, the total costs through September 30, 2015 are $0.2 million.

5. Estimated Future Costs

Q33. DOES EVERSOURCE EXPECT TO INCUR TRANSMISSION MERGER-RELATED COSTS AFTER SEPTEMBER 30, 2015?

A33. Yes. Eversource anticipates a relatively small amount of additional transmission-related merger-related transition costs subsequent to September 30, 2015, and expects that these costs will not exceed $1.5 million. Eversource will make a compliance filing identifying the future transmission merger-related costs following the close of the hold harmless period.

D. Allocation of Costs to the Transmission Function

Q34. PLEASE EXPLAIN HOW EVERSOURCE ALLOCATED ENTERPRISE-WIDE MERGER-RELATED COSTS TO THE TRANSMISSION FUNCTION.

A34. Incremental transaction and transition merger-related costs (e.g., bankers' fees) that were billed to Eversource were either recorded at the parent company level, and as result were entirely excluded from the operating companies' formula rates, or were recorded at the operating company level and subsequently removed from transmission formula rates. In order to determine the amount of enterprise-wide incremental merger costs that were related to the transmission function, Eversource utilized gross plant ratios. This asset-based allocation is a reasonable methodology, in view of the fact that the merger represents the combination of the corporate assets. These allocations are the same allocation methodologies that were used in the state proceedings for determining the amount of incremental enterprise-wide merger-related costs that were non-transmission related. The consistent use of allocations between the state proceedings and this proceeding is important and necessary to avoid any potential over or under-recovery of merger costs. Ms. Vaughan's Exhibit No. ES-116 details the allocation percentages used for transmission merger-related costs and Exhibit No. ES-201 details the costs allocated to transmission. In addition to these allocations, non-incremental merger-related costs were allocated to the transmission function using the methodology in the Eversource Companies' formula rates for allocating such costs.

IV. PROPOSED COST RECOVERY MECHANISM

Q35. HOW DO THE EVERSOURCE COMPANIES PROPOSE TO INCLUDE THE TRANSMISSION MERGER-RELATED COSTS IN THE TRANSMISSION SERVICE FORMULA RATES?

A35. The Eversource Companies are proposing to establish a regulatory asset in FERC Account No. 182.3 on June 1, 2016 for the Transmission Merger-Related Costs and are proposing to include these costs in the calculation of Transmission Related Administrative & General Expenses in the formula rates. This is Item II.H in ISO-NE OATT Attachment F (it is located in comparable sections of the other Transmission Service Formula Rates). However, because A&G costs are included in some of the Transmission Service Formula Rates on a company-wide basis (and then allocated to the transmission function), whereas Transmission Merger-Related Costs are *already* functionalized to transmission, two steps are necessary to accomplish this. First, all merger-related costs authorized for recovery by FERC or by state regulatory order are being removed from the definition of *total* Administrative and General Expenses (which includes all A&G expenses other than A&G expenses recorded to FERC Account Nos. 924, 928 and 930.1), as well as from the calculation of the transmission portion of FERC

Account No. 928 expenses.[9] Second, Transmission Merger-Related Costs are added as a line item to *Transmission Related* Administrative and General Expense. This ensures that the Transmission Merger-Related Costs are properly functionalized, and not included in the Transmission Service Formula Rates twice.

Q36. HOW DO THE EVERSOURCE COMPANIES PROPOSE TO INCLUDE THE TRANSMISSION MERGER-RELATED COSTS IN THE ISO-NE SCHEDULE 1 APPENDIX A RATES?

A36. This is largely accomplished in the same manner as such costs are included in the Transmission Service Formula Rates, with one exception. Schedule 1 recovers the cost of the investment in Dispatch Center Plant (plus an allocation of General Plant), whereas the Transmission Merger-Related Costs are calculated on a transmission level basis. Therefore, in order to determine the portion of Transmission Merger-Related Costs that are allocable to Dispatch Center costs, the Transmission Merger-Related Costs need to be multiplied by the ratio of Dispatch Center Plant (plus an allocation of General Plant) to Transmission Plant. This ratio is included in Schedule 1 as the "Dispatch Center Transmission Plant Allocation Factor."

[9] It is not necessary to remove these merger-related costs from FERC Accounts Nos. 924 (Property Insurance) or 930.1 (general advertising expenses) because no such costs are recorded to those accounts.

V. ALTERNATIVE COST RECOVERY MECHANISM

Q37. IF THE COMMISSION DOES NOT ACCEPT THE EVERSOURCE COMPANIES' ONE-YEAR AMORTIZATION PROPOSAL, DO THE EVERSOURCE COMPANIES HAVE AN ALTERNATIVE COST RECOVERY MECHANISM?

A37. Yes. In the event that the Commission does not accept the Eversource Companies' proposal to recover the Transmission Merger-Related Costs over a one-year period, the Eversource Companies propose that the Transmission Merger-Related Costs be amortized over a three-year period, and that carrying costs[10] be applied to the Transmission Merger-Related Costs. These carrying costs would be calculated monthly through May 31, 2016 and compounded semi-annually through December 31, 2015. In addition, the Eversource Companies propose that the unamortized balance of merger-related costs be included in rate base while the amortization proceeds. Under this alternative proposal, the same changes would be made to the Transmission Service Formula Rate as are discussed above with respect to the Eversource Companies' primary proposal. In addition, the Transmission Merger-Related Costs would be recorded as a regulatory asset in FERC Account No. 182.3 on June 1, 2016, and the costs would be amortized to the

[10] The monthly weighted AFUDC rate for each Company was used for the carrying cost calculation.

Eversource Companies' A&G accounts over a three-year period rather than over a one-year period. The Eversource Companies have calculated these carrying costs, and they are included in the total amount to be recorded in FERC Account No. 182.3 under the alternative proposal. Workpapers showing the calculation of these carrying charges are set forth in Exhibit No. ES-220. In addition, commencing June 1, 2016, the unamortized balance of the Transmission Merger-Related Costs (including carrying charges) in FERC Account No. 182.3 would be included in rate base, until the amortization is complete. To accomplish this, the Eversource Companies' unamortized balance of merger-related transmission costs recorded in FERC Account No. 182.3 as authorized by FERC would be included in "Other Regulatory Assets/Liabilities," which is a component of Transmission Investment Base (rate base).

Q38. WOULD THERE BE COMPARABLE CHANGES TO NE-ISO SCHEDULE 1 APPENDIX A?

A38. Yes, there would. And, for the reasons discussed above with respect to the Schedule 1 rates, the unamortized balance of merger-related transmission costs would be multiplied by the Dispatch Center Transmission Plant Allocation Factor, as defined above.

VI. REVENUE IMPACT

Q39. WHAT IS THE IMPACT OF THE EVERSOURCE COMPANIES' PROPOSED COST RECOVERY MECHANISM ON THE EVERSOURCE COMPANIES' TRANSMISSION SERVICE FORMULA RATES?

A39. Exhibit Nos. ES-214 through ES-219 calculate the revenue impact of the Eversource Companies' Proposed Cost Recovery Mechanism (one-year amortization) for the twelve-month period June 1, 2016 through May 31, 2017. In order to determine this revenue impact, the Eversource Companies calculated the transmission revenue requirements under each of the Transmission Service Formula Rates and under the ISO-NE OATT Schedule 1 Appendix A for 2016 assuming the changes that are the subject of this filing were not made (present rates), and then alternatively assuming the changes that are the subject of this filing were made (changed rates). For purposes of this calculation, we used the 2014 transmission revenue requirements plus estimated incremental transmission revenue requirements for 2015 and 2016 as an estimate for 2016. Since these estimated rates are subject to change based on actual costs, and since the purpose of the calculation is to show the difference between the two cost calculations, we used these revenue requirement calculations as an estimate for the twelve-month period beginning June 1, 2016. That is, we assumed that 7/12th of these transmission revenue requirements would be recovered in 2016, and 5/12th recovered in 2017. We then calculated the difference between these transmission revenue requirements under each of the Transmission Service Formula Rates and under the ISO-NE OATT Schedule 1 Appendix A rates. These are estimated calculations, as the actual charges will be based on actual transmission revenue requirements.

Q40. DID YOU MAKE A SIMILAR CALCULATION UNDER THE ALTERNATIVE COST RECOVERY MECHANISM?

A40. Yes. This calculation was performed in the same manner as the calculation above, except that it extended for thirty-six months rather than twelve. These calculations are shown in Exhibit Nos. ES-221 through ES-226. We used the 2016 transmission revenue requirements as an estimate for the transmission revenue requirements for 2017 and 2018. We then calculated the difference between these transmission revenue requirements under each of the Transmission Service Formula Rates and under the ISO-NE OATT Schedule 1 Appendix A rates.

Q41. WHAT DO THESE CALCULATIONS SHOW?

A41. The following is a summary of the increase in revenue requirement under both the proposed and alternative cost recovery mechanisms, for each rate:

Table B: Comparison of Revenue Impact Under Proposed Cost Recovery Mechanism and Alternative Cost Recovery Mechanism

Rate Schedule	Proposed Cost Recovery Mechanism (Millions)	Alternative Cost Recovery Mechanism (Millions)	Difference (Millions)
ISO-NE Attachment F-NU	$24.4	$32.2	$7.8
ISO-NE Attachment F-NSTAR	$8.8	$10.7	$1.9
ISO-NE Schedule 1, Appendix A	$0.1	$0.1	$-
Schedule 21-ES, Attachment ES-H	$1.5	$2.3	$0.8
Schedule 21-NSTAR, Attachments D and F	$1.8	$2.2	$0.4
Schedule 21-ES, Attachment ES-I	$1.2	$1.6	$0.4
Total	$37.8	$49.1	$11.3

As this table shows, the Proposed Cost Recovery Mechanism saves customers $11.3 million in transmission and Schedule 1 charges as compared to the Alternative Cost Recovery Mechanism.

Q42. THE TOTAL TRANSMISSION MERGER-RELATED COSTS ARE $37.4 MILLION, WHEREAS THE AMOUNT RECOVERED FROM CUSTOMERS UNDER THE PROPOSED COST RECOVERY MECHANISM IS $37.8 MILLION. WHY ARE THESE NUMBERS DIFFERENT?

A42. The $37.8 million figure reflects the impact on the total transmission revenue requirement of including $37.4 million of additional A&G expense in the formula rate. Certain other cost components within the formula rates are affected by the inclusion of the additional $37.4 million of A&G expenses. For example, the cash working capital allowance included in the formula rates is based on one-eighth of O&M expense and A&G expenses as calculated in the formula rates. This is simply the result of the operation of the existing formula rate provisions.

Q43. DOES THIS CONCLUDE YOUR TESTIMONY?

A43. Yes.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Eversource Energy Service Company) **Docket No. ER16-___-000**

AFFIDAVIT OF LISA M. COOPER

Lisa M. Cooper, being first duly sworn, deposes and says that she is the Lisa M. Cooper referred to in the foregoing testimony, that she has read such testimony and is familiar with the contents thereof, and that the answers therein are true and correct to the best of her knowledge, information, and belief.

Lisa M. Cooper
Lisa M. Cooper

Subscribed and sworn to before me this 17 day of February, 2016, by Lisa M. Cooper, proved to me on the basis of satisfactory evidence to be the person who appeared before me.

Sandra Foley
Notary Public

Commission Expires on: May 31, 2016

Exhibit No. ES-201

Total Merger Costs Summary Exhibit

Eversource Energy Service Company

Eversource Energy Service Company
Total Merger Costs Summary Exhibit

Ln.	(A) Merger Cost Category	Costs (B) 2010	(C) 2011	(D) 2012	(E) 2013	(F) 2014	(G) 2015	(H) (B)+(C)+ (D)+(E)+(F)+(G) Total	(I) Reference
	Transaction Costs								
1	Transaction Costs - Bankers' Fees	$ 11,826,000	$ 12,097,211	$ 24,116,050	$ -	$ -	$ -	$ 48,039,261	Exhibit No. ES-202, Page 1, Line 5
2	Transaction Costs Lawyers' Fees	$ 4,244,635	$ 2,058,706	$ 5,422,584	$ -	$ -	$ -	$ 11,725,925	Exhibit No. ES-203, Page 2, Line 39
3	Transaction Costs - Registration	$ 862	$ 2,125,574	$ -	$ -	$ -	$ -	$ 2,126,436	Exhibit No. ES-204, Page 1, Line 8
4	Transaction Costs - Consultants	$ 893,893	$ 490,570	$ -	$ -	$ -	$ -	$ 1,384,463	Exhibit No. ES-205, Page 1, Line 4
5	Regulatory Process Costs - Legal Fees	$ 1,243,313	$ 3,179,468	$ -	$ -	$ -	$ -	$ 4,422,781	Exhibit No. ES-206, Page 1, Line 19
6	Regulatory Process Costs - Registration S4	$ -	$ 37,152	$ -	$ -	$ -	$ -	$ 37,152	Exhibit No. ES-207, Page 1, Page 1
7	Regulatory Process Costs - Consultants	$ -	$ 246,770	$ -	$ -	$ -	$ -	$ 246,770	Exhibit No. ES-208, Page 1, Line 4
	Transition Costs								
8	Separation Costs - Separation Program	$ -	$ -	$ 20,540,396	$ 9,285,560	$ 2,635,803	$ -	$ 32,461,759	Exhibit No. ES-210, Page 1, Line 3
9	System Integration Costs	$ -	$ -	$ -	$ 5,756,121	$ 7,441,975	$ 67,273	$ 13,265,369	Exhibit No. ES-211, Page 1, Line 28
10	Other Transition Costs	$ 170,000	$ 3,359,651	$ 1,965,610	$ 1,511,505	$ 2,651,823	$ 854,899	$ 10,513,488	Exhibit No. ES-212, Page 2, Line 58
11	Separation Costs - Separation Assistance	$ -	$ -	$ 162,000	$ -	$ -	$ -	$ 162,000	Exhibit No. ES-213, Page 1, Line 1
12	Sub-Total (Sum Ln 1 - Ln 11):	$ 18,378,703	$ 23,595,102	$ 52,206,640	$ 16,553,186	$ 12,729,601	$ 922,172	$ 124,385,404	
	Allocation to Transmission	2010	2011	2012	2013	2014	2015	Total	
13	CL&P (Ln 12 * Ln 28)	$ 2,547,288	$ 3,270,281	$ 7,235,840	$ 2,294,272	$ 1,764,323	$ 127,813	$ 17,239,817	
14	NSTAR Electric (Ln 12 * Ln 29)	$ 1,499,702	$ 1,925,360	$ 4,260,062	$ 1,350,740	$ 1,038,735	$ 75,249	$ 10,149,848	
15	PSNH (Ln 12 * Ln 30)	$ 577,091	$ 740,886	$ 1,639,288	$ 519,770	$ 399,709	$ 28,956	$ 3,905,700	
16	WMECO (Ln 12 * Ln 31)	$ 685,526	$ 880,097	$ 1,947,308	$ 617,434	$ 474,814	$ 34,397	$ 4,639,576	
17	Sub-Total Transmission (Sum Ln 13 - Ln 16):	$ 5,309,607	$ 6,816,624	$ 15,082,498	$ 4,782,216	$ 3,677,581	$ 266,415	$ 35,934,941	
	Non-Incremental Internal Labor Costs								
18	CL&P	$ -	$ 663,346	$ 105,430	$ -	$ -	$ -	$ 768,776	Exhibit No. ES-209, Page 1, Line 8
19	NSTAR Electric	$ -	$ 268,426	$ 99,250	$ -	$ -	$ -	$ 367,676	Exhibit No. ES-209, Page 1, Line 16
20	PSNH	$ -	$ 146,438	$ 21,487	$ -	$ -	$ -	$ 167,925	Exhibit No. ES-209, Page 1, Line 24
21	WMECO	$ -	$ 95,851	$ 20,637	$ -	$ -	$ -	$ 116,488	Exhibit No. ES-209, Page 1, Line 32
22	Total Non-Incremental Internal Labor Costs (Sum Ln 18 - Ln 21):	$ -	$ 1,174,061	$ 246,804	$ -	$ -	$ -	$ 1,420,865	
	Total Transmission Costs								
23	CL&P (Ln 13 + Ln 18)	$ 2,547,288	$ 3,933,627	$ 7,341,270	$ 2,294,272	$ 1,764,323	$ 127,813	$ 18,008,593	
24	NSTAR Electric (Ln 14 + Ln 19)	$ 1,499,702	$ 2,193,786	$ 4,359,312	$ 1,350,740	$ 1,038,735	$ 75,249	$ 10,517,524	
25	PSNH (Ln 15 + Ln 20)	$ 577,091	$ 887,324	$ 1,660,775	$ 519,770	$ 399,709	$ 28,956	$ 4,073,625	
26	WMECO (Ln 16 + Ln 21)	$ 685,526	$ 975,948	$ 1,967,945	$ 617,434	$ 474,814	$ 34,397	$ 4,756,064	
27	Total Transmission (Sum Ln 23 - Ln 26):	$ 5,309,607	$ 7,990,685	$ 15,329,302	$ 4,782,216	$ 3,677,581	$ 266,415	$ 37,355,806	

Transmission Allocation Percentage

	Company	Allocation %	Reference
28	CL&P	13.86%	Exhibit No. ES-116, Page 1, Line 13 (D)
29	NSTAR Electric	8.16%	Exhibit No. ES-116, Page 1, Line 13 (J)
30	PSNH	3.14%	Exhibit No. ES-116, Page 1, Line 13 (L)
31	WMECO	3.73%	Exhibit No. ES-116, Page 1, Line 13 (G)

Exhibit No. ES-202

Transaction Costs - Bankers' Fees Exhibit

Eversource Energy Service Company

Eversource Energy Service Company
Transaction Costs - Bankers' Fees Exhibit

		Costs			
	(A)	(B)	(C)	(D)	(E)=(B)+(C)+(D)
	Company	2010	2011	2012	Total
1	[redacted]	$ 5,433,263	$ 5,412,215	$ 10,811,666	$ 21,657,144
2		$ 2,579,445	$ 2,881,720	$ 5,729,049	$ 11,190,214
3		$ 2,525,920	$ 2,512,076	$ 5,075,335	$ 10,113,331
4		$ 1,287,372	$ 1,291,200	$ 2,500,000	$ 5,078,572
5	**Total (Sum Ln 1 - Ln 4)**	$ 11,826,000 (a)	$ 12,097,211 (a)	$ 24,116,050 (a)	$ 48,039,261 (a)

These companies provided financial advisory and analyses services in connection with the merger.

(a) Exhibit No. ES-103, Page 48, Line 11.

Exhibit No. ES-203

Transaction Costs - Lawyers' Fees Exhibit

Eversource Energy Service Company

Eversource Energy Service Company
Transaction Costs - Lawyers' Fees Exhibit

	(A) Company		Costs (B) 2010	(C) 2011	(D) 2012	(E)=(B)+(C)+(D) Total
1	[redacted]		$ 2,147,055	$ 880,948	$ 1,220,502	$ 4,248,505
2			$ 2,010,402	$ 1,036,474	$ 547,306	$ 3,594,182
3		(a)	$ -	$ -	$ 724,356	$ 724,356
4		(a)	$ -	$ -	$ 618,139	$ 618,139
5		(a)	$ -	$ -	$ 311,124	$ 311,124
6		(a)	$ -	$ -	$ 280,000	$ 280,000
7			$ -	$ -	$ 239,283	$ 239,283
8		(a)	$ -	$ -	$ 220,319	$ 220,319
9			$ -	$ -	$ 220,167	$ 220,167
10			$ -	$ -	$ 218,570	$ 218,570
11		(a)	$ -	$ -	$ 187,911	$ 187,911
12		(a)	$ -	$ -	$ 138,259	$ 138,259
13		(a)	$ 83,983	$ 20,093	$ -	$ 104,076
14		(a)	$ -	$ -	$ 101,241	$ 101,241
15			$ -	$ 100,003	$ -	$ 100,003
16			$ -	$ -	$ 90,533	$ 90,533
17			$ -	$ -	$ 60,000	$ 60,000
18		(a)	$ -	$ -	$ 56,561	$ 56,561
19		(a)	$ -	$ -	$ 47,570	$ 47,570
20		(a)	$ -	$ -	$ 46,793	$ 46,793
21		(a)	$ -	$ -	$ 34,116	$ 34,116
22		(a)	$ -	$ -	$ 32,500	$ 32,500
23		(a)	$ -	$ -	$ 21,833	$ 21,833
24		(a)	$ -	$ -	$ 21,077	$ 21,077
25			$ -	$ -	$ 16,641	$ 16,641
26		(b)	$ -	$ 6,750	$ 6,750	$ 13,500

Eversource Energy Service Company
Transaction Costs - Lawyers' Fees Exhibit

			Costs									
	(A) Company		(B) 2010			(C) 2011			(D) 2012			(E)=(B)+(C)+(D) Total
27	[redacted]		$ -			$ 9,013			$ -			$ 9,013
28			$ -			$ 3,850			$ 3,366			$ 7,216
29			$ -			$ -			$ 5,266			$ 5,266
30			$ -			$ -			$ 3,750			$ 3,750
31			$ 3,075			$ -			$ -			$ 3,075
32		(a)	$ -			$ 1,500			$ 1,500			$ 3,000
33		(a)	$ -			$ -			$ 2,873			$ 2,873
34			$ -			$ -			$ 1,358			$ 1,358
35			$ -			$ -			$ 880			$ 880
36		(a)	$ -			$ -			$ 641			$ 641
37			$ 120			$ 75			$ -			$ 195
38		(c)	$ -			$ -			$ (58,601)			$ (58,601)
39	**Total (Sum Ln 1 - Ln 38)**		$ 4,244,635	(d)		$ 2,058,706	(d)		$ 5,422,584	(d)		$ 11,725,925 (d)

(a) These costs represent legal services, filing fees, consultants and other services in connection with regulatory approvals and transfers of licenses and registrations. The classification of these expenses as Lawyers' Fees is consistent with the Merger Integration Reports filed with the CT PURA (Exhibit No. ES-101, page 47) and MA DPU (Exhibit No. ES-102, page 50).

(b) [redacted]

(c) [redacted]

(d) Exhibit No. ES-103, Page 48, Line 12.

Exhibit No. ES-204

Transaction Costs - Registration Exhibit

Eversource Energy Service Company

Eversource Energy Service Company
Transaction Costs - Registration Exhibit

		Costs					
	(A) Company	(B) 2010		(C) 2011		(D)= (B)+(C) Total	
1	[redacted]	$ 862		$ 726,332		$ 727,194	
2		$ -		$ 428,041		$ 428,041	
3		$ -		$ 426,261		$ 426,261	
4		$ -		$ 227,775		$ 227,775	
5		$ -		$ 128,132		$ 128,132	
6		$ -		$ 120,932		$ 120,932	
7		$ -		$ 68,101		$ 68,101	
8	**Total (Sum Ln 1 - Ln 7)**	$ 862	(a)	$ 2,125,574	(a)	$ 2,126,436	(a)

These companies provided services related to the conversion of registration, special stockholder meetings, and acted as the stock transfer agent.

(a) Exhibit No. ES-103, Page 48, Line 13.

Exhibit No. ES-205

Transaction Costs - Consultants Exhibit

Eversource Energy Service Company

Eversource Energy Service Company
Transaction Costs - Consultants Exhibit

		Costs						
	(A)	**(B)**		**(C)**		**(D)=(B)+(C)**		
	Company	**2010**		**2011**		**Total**		
1	[redacted]	$ 446,363		$ 490,570		$ 936,933		
2		$ 224,530		$ -		$ 224,530		
3		$ 223,000		$ -		$ 223,000		
4	**Total (Sum Ln 1 - Ln 3)**	$ 893,893	(a)	$ 490,570	(a)	$ 1,384,463	(a)	

These companies provided accounting , tax and investor relation services in connection with the merger.

(a) Exhibit No. ES-103, Page 48, Line 14.

Exhibit No. ES-206

Regulatory Process Costs - Legal Fees Exhibit

Eversource Energy Service Company

Eversource Energy Service Company
Regulatory Process Costs - Legal Fees Exhibit

	(A) Company		Costs (B) 2010		Costs (C) 2011		Costs (D)=(B)+(C) Total	
1	[redacted]		$ 83,850		$ 1,115,080		$ 1,198,930	
2			$ 760,799		$ 174,836		$ 935,635	
3			$ 39,057		$ 501,469		$ 540,526	
4			$ 11,400		$ 271,825		$ 283,225	
5		(a)	$ -		$ 280,000		$ 280,000	
6			$ 154,953		$ 96,407		$ 251,360	
7			$ 20,930		$ 223,330		$ 244,260	
8			$ 151,124		$ 42,898		$ 194,022	
9		(b)	$ -		$ 179,917		$ 179,917	
10		(a)	$ -		$ 161,502		$ 161,502	
11			$ 5,000		$ 80,000		$ 85,000	
12			$ 12,700		$ 16,893		$ 29,593	
13			$ -		$ 21,491		$ 21,491	
14			$ 3,500		$ 4,581		$ 8,081	
15		(a)	$ -		$ 7,001		$ 7,001	
16		(a)	$ -		$ 893		$ 893	
17			$ -		$ 791		$ 791	
18			$ -		$ 554		$ 554	
19	**Total (Sum Ln 1 - Ln 18)**		$ 1,243,313	(c)	$ 3,179,468	(c)	$ 4,422,781	(c)

(a) These costs represent legal services, filing fees, consultants and other services in connection with regulatory approvals and transfers of licenses and registrations. The classification of these expenses as Legal Fees is consistent with the Merger Integration Reports filed with the CT PURA (Exhibit No. ES-101, page 47) and MA DPU (Exhibit No. ES-102, page 50).

(b) [redacted]

(c) Exhibit No. ES-103, Page 48, Line 17.

Exhibit No. ES-207

Regulatory Process Costs - Registration S4 Exhibit

Eversource Energy Service Company

Eversource Energy Service Company
Regulatory Process Costs - Registration S4 Exhibit

		Costs	
	(A)	(B)	
	Company	2011	
1	[redacted]	$ 37,152	(a)

This company provided services related to the preparation of the S-4 Registration.

(a) The Merger Integration Report, Exhibit No. ES-103, page 47, line 18 included a Security Exchange Commission fee associated with the registration in the amount of $.3 M. This fee is excluded from this Exhibit because it was recorded to FERC Account No. 214 which is not included in the Eversource Companies' formula rates.

Exhibit No. ES-208

Regulatory Process Costs - Consultants Exhibit

Eversource Energy Service Company

Eversource Energy Service Company
Regulatory Process Costs - Consultants Exhibit

	(A) Company	Costs (B) 2011	
1	[redacted]	$ 164,667	
2		$ 74,107	
3		$ 7,996	
4	**Total (Sum Ln 1 - Ln 3)**	$ 246,770	(b)

These companies provided consulting services for regulatory issues related to the merger proceeding.

(a) [redacted]

(b) Exhibit No. ES-103, Page 47, Line 19.

Exhibit No. ES-209

Non-Incremental Internal Labor Costs

Eversource Energy Service Company

Eversource Energy Service Company
Non-Incremental Internal Labor Costs

		Costs		
	(A)	(B)	(C)	(D)=(B)+(C)
	FERC Account No.	2011	2012	Total
	CL&P			
1	560	$ -	$ -	$ -
2	561.1	$ -	$ -	$ -
3	566	$ 5,692	$ 515	$ 6,207
4	920	$ 641,255	$ 103,537	$ 744,792
5	921	$ 16,323	$ 706	$ 17,029
6	923	$ 59	$ 672	$ 731
7	926	$ 17	$ -	$ 17
8	Total (Sum Ln 1 -Ln 7)	$ 663,346	$ 105,430	$ 768,776
	NSTAR Electric			
9	560	46,189	1,874	$ 48,063
10	561.1	563	-	$ 563
11	566	-		$ -
12	920	109,560	28,547	$ 138,107
13	921	9,146	49,391	$ 58,537
14	923	102,968	19,438	$ 122,406
15	926	-		$ -
16	Total (Sum Ln 9 - Ln 15)	$ 268,426	$ 99,250	$ 367,676
	PSNH			
17	560	-		$ -
18	561.1	-		$ -
19	566	3,225	252	$ 3,477
20	920	139,497	20,799	$ 160,296
21	921	3,222	142	$ 3,364
22	923	14	126	$ 140
23	926	480	168	$ 648
24	Total (Sum Ln 17 - Ln 23)	$ 146,438	$ 21,487	$ 167,925
	WMECO			
25	560	-		$ -
26	561.1	-		$ -
27	566	1,546	-	$ 1,546
28	920	92,229	20,360	$ 112,589
29	921	2,065	142	$ 2,207
30	923	9	135	$ 144
31	926	2	-	$ 2
32	Total (Sum Ln 25 -Ln 31)	$ 95,851	$ 20,637	$ 116,488
	Total Eversource			
33	560	46,189	1,874	$ 48,063
34	561.1	563	-	$ 563
35	566	10,463	767	$ 11,230
36	920	982,541	173,243	$ 1,155,784
37	921	30,756	50,381	$ 81,137
38	923	103,050	20,371	$ 123,421
39	926	499	168	$ 667
40	Total (Sum Ln 33 - Ln 39)	$ 1,174,061	$ 246,804	$ 1,420,865

As a result of the FERC Audit Report in Docket No. FA12-10-000, Legacy NSTAR Electric refunded non-incremental merger-related internal labor costs recorded in sub account 39 that were included in the transmission formula rates. Legacy NSTAR Electric refunded these amounts in the June 2014 true-up process. Legacy NU (CL&P, PSNH and WMECO) issued a similar refund for amounts recorded in activity "ODEDT" that were included in transmission formula rates. Legacy NU refunded theses amounts in the June 2015 true-up process.

Exhibit No. ES-210

Separation Costs - Separation Program Exhibit

Eversource Energy Service Company

Eversource Energy Service Company
Separation Costs - Separation Program Exhibit

		Costs			
	(A)	(B)	(C)	(D)	(E)=(B)+(C)+(D)
	Company	2012	2013	2014	Total
1	Non-Executive Severance Costs	$ 20,386,345	$ 9,195,531	$ 2,635,803	$ 32,217,679 (a)
2	Restricted Stock Non-Executive Accrual	$ 154,051	$ 90,029	$ -	$ 244,080
3	**Total (Sum Ln 1 - Ln 2)**	$ 20,540,396 (b)	$ 9,285,560 (b)	$ 2,635,803 (b)	$ 32,461,759 (b)

(a) Exhibit No. ES-210, Page 8, Line 400 (B).
(b) Exhibit No. ES-103, Page 47, Line 2.

Eversource Energy Service Company
Separation Costs - Non Executive Severance Costs

Line	(A) Job Title	(B) Costs
1	ACCOUNT EXECUTIVE	$ [redacted]
2	ACCOUNTANT A	$
3	ACCOUNTANT A	$
4	ACCOUNTANT A	$
5	ACCOUNTANT B	$
6	Accounting Clerk A	$
7	Accounting Clerk A	$
8	Accounting Clerk A	$
9	Accounting Clerk A	$
10	Accounting Clerk A	$
11	Accounting Clerk A	$
12	ACCOUNTING CLERK A (SUNDRY BILLING)	$
13	Admin Coordinator	$
14	ADMINISTRATIVE ASSISTANT	$
15	ADMINISTRATIVE ASSISTANT	$
16	Administrative Assistant	$
17	ADMINISTRATIVE ASSISTANT	$
18	ADMINISTRATIVE ASSISTANT	$
19	ADMINISTRATIVE ASSISTANT	$
20	Administrative Assistant	$
21	Administrative Assistant A	$
22	ADMINISTRATIVE ASSISTANT A	$
23	ADMINISTRATIVE ASSISTANT A	$
24	ADMINISTRATIVE ASSISTANT B	$
25	ANALYST-GENERAL SERVICES	$
26	ASSISTANT GENERAL COUNSEL	$
27	Associate Accounting Analyst	$
28	ASSOCIATE ANALYST TRANSMISSION	$
29	ASSOCIATE BUSINESS GROUP ANALYST	$
30	ASSOCIATE CUSTOMER SERVICES TRAINING COORDINATOR	$
31	ASSOCIATE CUSTOMER SERVICES TRAINING COORDINATOR	$
32	ASSOCIATE CUSTOMER SERVICES TRAINING COORDINATOR	$
33	ASSOCIATE ENGINEER	$
34	ASSOCIATE GAS TRANSPORTATION ANALYST	$
35	ASSOCIATE REGULATORY PLANNING ANALYST	$
36	ASSOCIATE REGULATORY PLANNING ANALYST	$
37	Asst Treasurer, Asset Mgmt	$
38	Audit Manager, Cust Care & IT	$
39	BUSINESS DEVELOPMENT CONSULTANT	$
40	BUSINESS INTEGRATION MANAGER	$
41	Business Integration Manager	$
42	Business Integration Manager	$
43	Business Systems Analyst	$
44	BUSINESS UNIT RISK CONTROLLER	$
45	BUYER	$
46	Chief Accounting Clerk	$
47	CHIEF REPRODUCTION EQUIPMENT OPERATOR	$
48	Claims Specialist	$
49	CLERK	$
50	COMMUNICATIONS SPECIALIST	$
51	COMMUNICATIONS SPECIALIST	$
52	CONTRIBUTIONS PROCESSOR-COMMUNITY RELATIONS	$
53	CORPORATE INSURANCE MANAGER	$
54	CREDIT COUNSELOR	$
55	CREDIT COUNSELOR	$
56	CREDIT COUNSELOR	$
57	CREDIT COUNSELOR	$
58	CUSTOMER SERVICE CONSULTANT	$

Eversource Energy Service Company
Separation Costs - Non Executive Severance Costs

Line	(A) Job Title	(B) Costs
59	CUSTOMER SERVICE CONSULTANT	$ [redacted]
60	Customer Service Consultant	$
61	CUSTOMER SERVICES TRAINING COORDINATOR	$
62	CUSTOMER SERVICES TRAINING COORDINATOR	$
63	CUSTOMER SERVICES TRAINING COORDINATOR	$
64	CUSTOMER SERVICES TRAINING COORDINATOR	$
65	CUSTOMER SERVICES TRAINING COORDINATOR	$
66	DIRECTOR EMPLOYEE RELATIONS	$
67	Director, Enter Infor Srvcs	$
68	Director, Enterp Strat & Bus Dev	$
69	Director, Facilities Management	$
70	Director, Internal Audit	$
71	Director, Labor Relations	$
72	Director, Load Fore & Analysis	$
73	Director, Municipal Relations and Siting	$
74	Director, Tech Srvc Del & Mgmt	$
75	Director, Transmission Asset Strategy	$
76	DIRECTOR-CUSTOMER EXPERIENCE SUPPORT	$
77	Director-Enterprise Planning and Development	$
78	DIRECTOR-FINANCIAL PLANNING AND ANALYSIS	$
79	Director-IT Operations	$
80	DIRECTOR-IT STRATEGY & TECHNICAL SERVICES	$
81	Director-Training	$
82	DIRECTOR-WMECO COMMUNICATIONS	$
83	DIVISION MANAGER	$
84	ECONOMIC DEVPMNT & COMMUNITY RELATIONS COORDINATOR	$
85	ECONOMIC DEVPMNT & COMMUNITY RELATIONS COORDINATOR	$
86	ENERGY SERVICES REPRESENTATIVE	$
87	ENERGY SERVICES REPRESENTATIVE	$
88	ENERGY SERVICES REPRESENTATIVE	$
89	ENERGY SERVICES REPRESENTATIVE	$
90	ENERGY SERVICES REPRESENTATIVE	$
91	ENGINEERING TECHNICIAN A	$
92	ENGINEERING TECHNICIAN A	$
93	ENVIRONMENTAL COORDINATOR	$
94	ENVIRONMENTAL COORDINATOR	$
95	ENVIRONMENTAL COORDINATOR	$
96	ENVIRONMENTAL RECORDS TECHNICIAN A	$
97	ENVIRONMENTAL TECHNICIAN A	$
98	ENVIRONMENTAL TECHNICIAN A	$
99	Executive Assistant	$
100	Executive Assistant	$
101	Executive Director-IT	$
102	Executive Secretary	$
103	Executive Secretary	$
104	FINANCIAL ANALYST	$
105	FINANCIAL ANALYST	$
106	Fixed Asset Analyst	$
107	Fixed Asset Analyst	$
108	Fixed Asset Analyst	$
109	Health Administrator	$
110	HEALTH UNIT ASSISTANT C	$
111	HR CONSULTANT	$
112	HR CONSULTANT	$
113	HR CONSULTANT	$
114	HR CONSULTANT	$
115	HR REPRESENTATIVE	$
116	Human Resources Business Partner	$

Eversource Energy Service Company
Separation Costs - Non Executive Severance Costs

Line	(A) Job Title		(B) Costs
117	Internal Auditor	$	[redacted]
118	IT ADMINISTRATIVE REPRESENTATIVE A	$	[redacted]
119	IT Net Analyst -LAN/WAN-Lvl 4	$	[redacted]
120	IT Bus App Sys Developer-Lvl 3	$	[redacted]
121	IT Bus App Sys Developer-Lvl 4	$	[redacted]
122	IT Bus App Sys Developer-Lvl 4	$	[redacted]
123	IT Bus App Sys Developer-Lvl 4	$	[redacted]
124	IT Bus App Sys Developer-Lvl 4	$	[redacted]
125	IT Bus App Sys Developer-Lvl 4	$	[redacted]
126	IT BUSINESS ANALYST - LEVEL 4	$	[redacted]
127	IT BUSINESS APPLICATION SYSTEMS DEVELOPER- LEVEL 1	$	[redacted]
128	IT BUSINESS APPLICATION SYSTEMS DEVELOPER- LEVEL 1	$	[redacted]
129	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 2	$	[redacted]
130	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 2	$	[redacted]
131	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3	$	[redacted]
132	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3	$	[redacted]
133	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3	$	[redacted]
134	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3	$	[redacted]
135	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3	$	[redacted]
136	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3	$	[redacted]
137	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3	$	[redacted]
138	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3	$	[redacted]
139	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3	$	[redacted]
140	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3	$	[redacted]
141	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3	$	[redacted]
142	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3	$	[redacted]
143	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3	$	[redacted]
144	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3	$	[redacted]
145	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3	$	[redacted]
146	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3	$	[redacted]
147	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3	$	[redacted]
148	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3	$	[redacted]
149	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3	$	[redacted]
150	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3	$	[redacted]
151	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3	$	[redacted]
152	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3	$	[redacted]
153	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3	$	[redacted]
154	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3	$	[redacted]
155	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3	$	[redacted]
156	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3	$	[redacted]
157	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3	$	[redacted]
158	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3	$	[redacted]
159	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 3	$	[redacted]
160	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 4	$	[redacted]
161	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 4	$	[redacted]
162	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 4	$	[redacted]
163	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 4	$	[redacted]
164	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 4	$	[redacted]
165	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 4	$	[redacted]
166	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 4	$	[redacted]
167	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 4	$	[redacted]
168	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 4	$	[redacted]
169	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 4	$	[redacted]
170	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 4	$	[redacted]
171	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 4	$	[redacted]
172	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 4	$	[redacted]
173	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 4	$	[redacted]
174	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 4	$	[redacted]

Eversource Energy Service Company
Separation Costs - Non Executive Severance Costs

Line	(A) Job Title	(B) Costs
175	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 4	$ [redacted]
176	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 4	$
177	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 4	$
178	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 4	$
179	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 4	$
180	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 4	$
181	IT BUSINESS APPLICATION SYSTEMS DEVELOPER LEVEL 4	$
182	IT BUSINESS SOLUTIONS ANALYST-LEVEL 3	$
183	IT BUSINESS SOLUTIONS ANALYST-LEVEL 3	$
184	IT BUSINESS SOLUTIONS ANALYST-LEVEL 4	$
185	IT BUSINESS SOLUTIONS ANALYST-LEVEL 4	$
186	IT CLIENT SERVICES REPRESENTATIVE - LEVEL 3	$
187	IT CLIENT SERVICES REPRESENTATIVE - LEVEL 3	$
188	IT CLIENT SERVICES REPRESENTATIVE - LEVEL 3	$
189	IT CLIENT SERVICES REPRESENTATIVE - LEVEL 4	$
190	IT COMPUTER OPERATOR - LEVEL 4	$
191	IT COMPUTER OPERATOR - LEVEL 4	$
192	IT COMPUTER OPERATORS - LEVEL 3 (SW)	$
193	IT COMPUTER OPERATORS - LEVEL 3 (SW)	$
194	IT COMPUTER OPERATORS - LEVEL 3 (SW)	$
195	IT COMPUTER OPERATORS - LEVEL 3 (SW)	$
196	IT COMPUTER OPERATORS - LEVEL 3 (SW)	$
197	IT COMPUTER OPERATORS - LEVEL 3 (SW)	$
198	IT COMPUTER SECURITY TECHNICIAN - LEVEL 1	$
199	IT CONSULTANT	$
200	IT CONSULTANT-LEVEL 1	$
201	IT CONSULTANT-LEVEL 1	$
202	IT CONSULTANT-LEVEL 1	$
203	IT CONSULTANT-LEVEL 1	$
204	IT DATABASE ADMINISTRATOR - LEVEL 3	$
205	IT DATABASE ADMINISTRATOR - LEVEL 4	$
206	IT DATABASE ADMINISTRATOR - LEVEL 4	$
207	IT DATABASE ADMINISTRATOR - LEVEL 4	$
208	IT DATABASE ADMINISTRATOR - LEVEL 4	$
209	IT DATABASE ADMINISTRATOR - LEVEL 4	$
210	IT Database Administrator-Lvl 4	$
211	IT Database Administrator-Lvl 4	$
212	IT INFORMATION MODELER - LEVEL 4	$
213	IT INFORMATION MODELER - LEVEL 4	$
214	IT MANAGER - APPLICATION DEVELOPMENT	$
215	IT Net Analyst -LAN/WAN-Lvl 4	$
216	IT NETWORK SYSTEMS ENGINEER - LEVEL 4	$
217	IT PROCESS ANALYST-LEVEL 3	$
218	IT PRODUCT MANAGER LEVEL 3	$
219	IT PROJECT COORDINATOR - LEVEL 4	$
220	IT PROJECT MANAGER - LEVEL 2	$
221	IT PROJECT MANAGER - LEVEL 3	$
222	IT Project Manager-Level 3	$
223	IT SECURITY ENGINEER LEVEL 4	$
224	IT SUPERVISOR, COMPUTER OPERATIONS	$
225	IT Supervisor, UNIX	$
226	IT Supervisor, X86	$
227	IT Supervisor-Appl Development	$
228	IT Supervisor-Appl Development	$
229	IT Supervisor-Appl Development	$
230	IT SUPERVISOR-APPLICATION DEVELOPMENT	$
231	IT SUPERVISOR-STORAGE	$
232	IT SUPPORT CENTER CONSULTANT - LEVEL 3	$

Eversource Energy Service Company
Separation Costs - Non Executive Severance Costs

Line	(A) Job Title	(B) Costs
233	IT SUPPORT CENTER CONSULTANT - LEVEL 3	$ [redacted]
234	IT SUPPORT CENTER CONSULTANT - LEVEL 3	$
235	IT SUPPORT CENTER CONSULTANT - LEVEL 3	$
236	IT SUPPORT CENTER CONSULTANT - LEVEL 3	$
237	IT SYSTEM ADMINISTRATION AND CONTROL - LEVEL 3	$
238	IT SYSTEM ADMINISTRATION AND CONTROL - LEVEL 3	$
239	IT SYSTEM ADMINISTRATION AND CONTROL - LEVEL 3	$
240	IT SYSTEM ADMINISTRATION AND CONTROL - LEVEL 3	$
241	IT SYSTEM ADMINISTRATION AND CONTROL - LEVEL 4	$
242	IT SYSTEM ADMINISTRATION AND CONTROL - LEVEL 4	$
243	IT SYSTEMS ENGINEER - LEVEL 2	$
244	IT SYSTEMS ENGINEER - LEVEL 3	$
245	IT SYSTEMS ENGINEER - LEVEL 3	$
246	IT SYSTEMS ENGINEER - LEVEL 3	$
247	IT SYSTEMS ENGINEER - LEVEL 3	$
248	IT SYSTEMS ENGINEER - LEVEL 3	$
249	IT SYSTEMS ENGINEER - LEVEL 3	$
250	IT SYSTEMS ENGINEER - LEVEL 3	$
251	IT SYSTEMS ENGINEER - LEVEL 3	$
252	IT SYSTEMS ENGINEER - LEVEL 3	$
253	IT SYSTEMS ENGINEER - LEVEL 3	$
254	IT SYSTEMS ENGINEER - LEVEL 4	$
255	IT SYSTEMS ENGINEER - LEVEL 4	$
256	IT SYSTEMS ENGINEER - LEVEL 4	$
257	IT SYSTEMS ENGINEER - LEVEL 4	$
258	IT SYSTEMS ENGINEER - LEVEL 4	$
259	IT SYSTEMS ENGINEER - LEVEL 4	$
260	IT SYSTEMS ENGINEER - LEVEL 4	$
261	IT SYSTEMS ENGINEER - LEVEL 4	$
262	IT SYSTEMS ENGINEER - LEVEL 4	$
263	IT SYSTEMS ENGINEER - LEVEL 4	$
264	IT SYSTEMS ENGINEER - LEVEL 4	$
265	IT SYSTEMS ENGINEER - LEVEL 4	$
266	IT SYSTEMS ENGINEER - LEVEL 4	$
267	IT SYSTEMS ENGINEER - LEVEL 4	$
268	IT SYSTEMS ENGINEER - LEVEL 4	$
269	IT SYSTEMS ENGINEER - LEVEL 4	$
270	IT SYSTEMS ENGINEER - LEVEL 4	$
271	IT SYSTEMS ENGINEER - LEVEL 4	$
272	IT SYSTEMS ENGINEER - LEVEL 4	$
273	IT SYSTEMS ENGINEER - LEVEL 4	$
274	IT SYSTEMS ENGINEER - LEVEL 4	$
275	IT Systems Engineer-Level 3	$
276	IT Systems Engineer-Level 3	$
277	IT Systems Engineer-Level 4	$
278	IT Systems Engineer-Level 4	$
279	IT SYSTEMS ENGINEER-OPERATIONS - LEVEL 3	$
280	IT Technician-Level 2	$
281	IT Technician-Level 2	$
282	IT TECHNICIAN-LEVEL 3	$
283	IT TECHNICIAN-LEVEL 4	$
284	IT TECHNICIAN-LEVEL 4	$
285	IT TECHNOLOGY MANAGER	$
286	IT TECHNOLOGY MANAGER	$
287	IT TECHNOLOGY MANAGER	$
288	IT TECHNOLOGY MANAGER	$
289	IT VOICE COMMUNICATIONS ANALYST - LEVEL 3	$
290	IT VOICE COMMUNICATIONS ANALYST - LEVEL 3	$

Eversource Energy Service Company
Separation Costs - Non Executive Severance Costs

Line	(A) Job Title	(B) Costs
291	IT WEBMASTER - LEVEL 3	$ [redacted]
292	IT WEBMASTER - LEVEL 3	$
293	LEGAL ADMINISTRATIVE ASSISTANT	$
294	LEGAL ADMINISTRATIVE ASSISTANT	$
295	LEGAL ADMINISTRATIVE ASSISTANT	$
296	LIABILITY CLAIMS MANAGER-LEVEL 3	$
297	LIABILITY CLAIMS MANAGER-LEVEL 3	$
298	Manager, Audit	$
299	Manager, Community Relations	$
300	Manager, Corporate Security	$
301	Manager, Directory & Appl Srvs	$
302	Manager, Facilities Services	$
303	Manager, Power Systems Operations Training	$
304	Manager, Security & Risk Mgmt	$
305	Manager, Trans Susta&Dist SC	$
306	MANAGER-ACCOUNTING POLICIES AND INTERNAL CONTROLS	$
307	MANAGER-BUSINESS SERVICES GROUP	$
308	MANAGER-BUSINESS SERVICES GROUP (CL&P)	$
309	MANAGER-CL&P COMMUNICATIONS	$
310	MANAGER-CORPORATE FINANCIAL FORECASTING	$
311	MANAGER-CUSTOMER OPERATIONS	$
312	MANAGER-CUSTOMER SERVICE TRAINING	$
313	MANAGER-ECONOMIC DEVELOPMENT & COMMUNITY RELATIONS	$
314	MANAGER-REGULATORY POLICY	$
315	MANAGER-TRANSMISSION CONTRACTS	$
316	MANAGER-TREASURY OPERATIONS	$
317	MANAGER-UG REVENUE STREAM OPERATIONS	$
318	MANAGER-UTILITY GROUP ASSET STRATEGY	$
319	MGR-CUST BLNG SVCS & LRG PWR BILLING (IO)	$
320	MGR-TRNS PERFRMCE ANALYS & REPORTING & DOC CNTRL	$
321	OCCUPATIONAL HEALTH NURSE	$
322	Power Plant Program Manager	$
323	PRICING SUPPORT SPECIALIST	$
324	PROCESS ANALYST-CL&P SYSTEM	$
325	Program Manager, Accounting	$
326	PROJECT MANAGER	$
327	PROJECT MANAGER	$
328	Project Manager, Bus Sys Mgmt	$
329	PROJECT MANAGER-ENTERPRISE PLANNING	$
330	PROJECT MANAGER-PILOT CUSTOMER EXPERIENCE (IO)	$
331	PROJECT MANAGER-SYSTEM RECRUITMENT	$
332	PUBLIC AFFAIRS SPECIALIST	$
333	QUALITY ASSURANCE ADVISOR	$
334	QUALITY ASSURANCE SPECIALIST	$
335	REGIONAL CONSERVATION & LOAD MANAGEMENT MANAGER	$
336	REGIONAL SUPERVISOR-FACILITIES	$
337	Revenue Assurance Specialist	$
338	Revenue Assurance Specialist	$
339	REVENUE INVESTIGATOR	$
340	REVENUE INVESTIGATOR	$
341	REVENUE PROTECTION RECOVERY SPECIALIST	$
342	REVENUE REQUIREMENTS ANALYST	$
343	Safety and Environmental Coordinator-Transmissions	$
344	SCADA / EMS TECHNOLOGY SUPPORT COORDINATOR	$
345	SENIOR ACCOUNT EXECUTIVE-CL&P	$
346	SENIOR ACCOUNT EXECUTIVE-CL&P	$
347	Senior Accounting Analyst	$
348	Senior Accounting Clerk	$

Eversource Energy Service Company
Separation Costs - Non Executive Severance Costs

Line	(A) Job Title		(B) Costs
349	SENIOR ANALYST	$	[redacted]
350	SENIOR BUYERS ASSISTANT	$	[redacted]
351	SENIOR CONTRACT SPECIALIST	$	[redacted]
352	SENIOR COUNSEL	$	[redacted]
353	SENIOR ECONOMIC AND LOAD ANALYST	$	[redacted]
354	SENIOR FINANCIAL ANALYST	$	[redacted]
355	SENIOR HR CONSULTANT	$	[redacted]
356	SENIOR HR REPRESENTATIVE	$	[redacted]
357	Senior Internal Auditor	$	[redacted]
358	Senior Planning Analyst	$	[redacted]
359	SENIOR REGULATORY INFORMATION PROCESSOR	$	[redacted]
360	SENIOR REVENUE REQUIREMENTS ANALYST	$	[redacted]
361	Solutions Architect	$	[redacted]
362	SOURCING CONSULTANT	$	[redacted]
363	Sr Budget & Fore Analyst	$	[redacted]
364	Sr Contract Agent	$	[redacted]
365	Sr Contract Agent	$	[redacted]
366	Sr Energy Supply Analyst	$	[redacted]
367	Sr Finan Analyst, Invest Plng	$	[redacted]
368	Sr Financial Reporting Analyst	$	[redacted]
369	Sr Purchasing Agent	$	[redacted]
370	Sr. Internal Auditor	$	[redacted]
371	Sr. Internal Auditor	$	[redacted]
372	SUPERVISOR CALL CENTER	$	[redacted]
373	Supervisor, Accounts Payable	$	[redacted]
374	Supervisor, Call Center	$	[redacted]
375	Supervisor, Facilities Mgmt	$	[redacted]
376	Supervisor, Purchasing	$	[redacted]
377	SUPERVISOR-ACCOUNT EXECUTIVES	$	[redacted]
378	SUPERVISOR-CUSTOMER EXPERIENCE BUDGETS AND GOALS	$	[redacted]
379	SUPERVISOR-CUSTOMER SERVICE	$	[redacted]
380	SUPERVISOR-CUSTOMER SERVICE	$	[redacted]
381	SUPERVISOR-CUSTOMER SERVICE	$	[redacted]
382	SUPERVISOR-CUSTOMER SERVICE	$	[redacted]
383	SUPERVISOR-ENGINEERING & DESIGN	$	[redacted]
384	SUPERVISOR-MATERIALS MANAGEMENT	$	[redacted]
385	Tax Research Principal	$	[redacted]
386	TEAM LEADER	$	[redacted]
387	TEAM LEADER-CUSTOMER EXPERIENCE	$	[redacted]
388	TEAM LEADER-CUSTOMER EXPERIENCE	$	[redacted]
389	Team Leader-Transmission Contracts	$	[redacted]
390	TECHNICAL ASSOCIATE	$	[redacted]
391	TECHNICAL ASSOCIATE	$	[redacted]
392	TECHNICAL ASSOCIATE-CUSTOMER SERVICE CONSULTANT	$	[redacted]
393	TRANSMISSION CONTRACTS ASSISTANT (SW)	$	[redacted]
394	Transportation Assistant A (SW)	$	[redacted]
395	WORKER S COMPENSATION ANALYST	$	[redacted]
396	WORKERS COMPENSATION ASSISTANT A	$	[redacted]
397	WORKFORCE SCHEDULING ASSOCIATE	$	[redacted]
398	Associated Medical Costs Paid - non employee specific	$	[redacted]
399	Outplacement Services Paid - non employee specific	$	[redacted]
400	**Total (Sum Ln 1 - Ln 399)**	$	32,217,678.95

Exhibit No. ES-211

System Integration Costs Exhibit

Eversource Energy Service Company

Eversource Energy Service Company
System Integration Costs Exhibit

		Costs			
	(A) Vendor	(B) 2013	(C) 2014	(D) 2015	(E)= (B)+(C)+(D) Total
1	[redacted]	$ -	$ 368,153	$ -	$ 368,153
2	[redacted]	$ 4,549	$ 4,476	$ -	$ 9,025
3	[redacted]	$ 359,495	$ -	$ -	$ 359,495
4	[redacted]	$ 25,000	$ -	$ -	$ 25,000
5	[redacted]	$ 117,951	$ -	$ -	$ 117,951
6	[redacted]	$ -	$ -	$ 8,311	$ 8,311
7	[redacted]	$ 25,450	$ -	$ -	$ 25,450
8	[redacted]	$ 10,822	$ -	$ -	$ 10,822
9	[redacted]	$ -	$ 305,627	$ -	$ 305,627
10	[redacted]	$ -	$ 41,000	$ 99,817	$ 140,817
11	[redacted]	$ 242,141	$ 543,506	$ (19,482) (a)	$ 766,165
12	[redacted]	$ 193,123	$ 701,700	$ -	$ 894,823
13	[redacted]	$ 768,404	$ 2,717,333	$ (87,543) (a)	$ 3,398,194
14	[redacted]	$ 150,000	$ -	$ -	$ 150,000
15	[redacted]	$ 38,525	$ 374,765	$ -	$ 413,290
16	[redacted]	$ 1,387,330	$ 483,657	$ (23,452) (a)	$ 1,847,535
17	[redacted]	$ 10,831	$ -	$ -	$ 10,831
18	[redacted]	$ -	$ 3,894	$ -	$ 3,894
19	[redacted]	$ -	$ 180,745	$ -	$ 180,745
20	[redacted]	$ -	$ 3,537	$ -	$ 3,537
21	[redacted]	$ 79,000	$ 838,413	$ 89,622	$ 1,007,035
22	[redacted]	$ 2,123,917	$ 680,140	$ -	$ 2,804,057
23	[redacted]	$ -	$ 5,226	$ -	$ 5,226
24	[redacted]	$ 1,520	$ -	$ -	$ 1,520
25	[redacted]	$ -	$ 149,803	$ -	$ 149,803
26	[redacted]	$ -	$ 6,000	$ -	$ 6,000
27	[redacted]	$ 218,063	$ 34,000	$ -	$ 252,063
28	**Total (Sum Ln 1 - Ln 27)**	$ 5,756,121 (b)	$ 7,441,975 (b)	$ 67,273 (b)	$ 13,265,369 (b)

(a) Negative costs are due to the reversal of unvouchered liabilities and journal entries.
(b) Exhibit No. ES-103, Page 48, Line 6.

See Exhibit ES-211, Page 2 of 2 for description of the vendor's Scope of Work.

PUBLIC VERSION
PROTECTED MATERIALS REDACTED

Eversource Energy Service Company
System Integration Costs Exhibit
Detailed Scope of Work

	Vendor	Scope of Work
1	[redacted]	
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Exhibit No. ES-212

Other Transition Costs Exhibit

Eversource Energy Service Company

Eversource Energy Service Company
Other Transition Costs Exhibit

	(A) Company	Costs (B) 2010	(C) 2011	(D) 2012	(E) 2013	(F) 2014	(G) 2015	(H)= (B)+(C)+(D)+(E)+(F)+(G) Total
1	[redacted]	$ -	$ -	$ -	$ -	$ 44,301	$ -	$ 44,301
2	[redacted]	$ -	$ -	$ -	$ 9,845	$ -	$ -	$ 9,845
3	[redacted]	$ -	$ -	$ 2,244	$ -	$ -	$ -	$ 2,244
4	[redacted]	$ -	$ -	$ -	$ 375	$ -	$ -	$ 375
5	[redacted]	$ -	$ 17,529	$ 22,593	$ 8,873	$ -	$ -	$ 48,995
6	[redacted]	$ -	$ -	$ -	$ 5,458	$ -	$ -	$ 5,458
7	[redacted]	$ -	$ -	$ -	$ 15,000	$ -	$ -	$ 15,000
8	[redacted]	$ -	$ -	$ -	$ 10,155	$ -	$ -	$ 10,155
9	[redacted]	$ -	$ 3,150	$ -	$ -	$ -	$ -	$ 3,150
10	[redacted]	$ -	$ -	$ -	$ 160,275	$ -	$ -	$ 160,275
11	[redacted]	$ -	$ 12,599	$ -	$ -	$ -	$ -	$ 12,599
12	[redacted]	$ -	$ -	$ 9,500	$ -	$ -	$ -	$ 9,500
13	[redacted]	$ -	$ -	$ -	$ 4,000	$ -	$ -	$ 4,000
14	[redacted]	$ -	$ -	$ -	$ 885	$ -	$ -	$ 885
15	[redacted]	$ -	$ -	$ 305,651	$ -	$ -	$ -	$ 305,651
16	[redacted]	$ -	$ 71,406	$ -	$ -	$ -	$ -	$ 71,406
17	[redacted]	$ -	$ -	$ 124,900	$ -	$ -	$ -	$ 124,900
18	[redacted]	$ -	$ -	$ -	$ 218,372	$ 12,837	$ -	$ 231,209
19	[redacted]	$ -	$ -	$ -	$ -	$ 112,814	$ -	$ 112,814
20	[redacted]	$ -	$ -	$ 5,840	$ -	$ -	$ -	$ 5,840
21	[redacted]	$ -	$ -	$ -	$ 1,973	$ -	$ -	$ 1,973
22	[redacted]	$ -	$ -	$ -	$ 96,622	$ 34,147	$ 411,290	$ 542,059
23	[redacted]	$ -	$ -	$ 14,000	$ -	$ -	$ -	$ 14,000
24	[redacted]	$ -	$ 59,299	$ 30,491	$ (27,335) (a)	$ -	$ -	$ 62,455
25	[redacted]	$ -	$ 150,986	$ -	$ -	$ -	$ -	$ 150,986
26	[redacted]	$ -	$ -	$ 6,050	$ -	$ -	$ -	$ 6,050
27	[redacted]	$ -	$ -	$ 5,857	$ -	$ -	$ -	$ 5,857
28	[redacted]	$ -	$ 15,700	$ -	$ -	$ -	$ -	$ 15,700
29	[redacted]	$ -	$ -	$ 83,014	$ 50,888	$ -	$ -	$ 133,902
30	[redacted]	$ -	$ -	$ -	$ -	$ 302,804	$ -	$ 302,804
31	[redacted]	$ -	$ -	$ 2,645	$ -	$ -	$ -	$ 2,645
32	[redacted]	$ -	$ -	$ 95,535	$ -	$ -	$ -	$ 95,535
33	[redacted]	$ -	$ -	$ -	$ 6,844	$ -	$ -	$ 6,844
34	[redacted]	$ -	$ 3,421	$ 172,611	$ 67,929	$ (4,101) (a)	$ 1,641	$ 241,501
35	[redacted]	$ -	$ 61,349	$ 52,551	$ -	$ -	$ -	$ 113,900
36	[redacted]	$ -	$ -	$ 3,575	$ 20,021	$ 715	$ -	$ 24,311
37	[redacted]	$ -	$ -	$ -	$ 134,072	$ 178,640	$ 476	$ 313,188
38	[redacted]	$ 170,000	$ 2,905,414	$ 376,015	$ -	$ -	$ -	$ 3,451,429
39	[redacted]	$ -	$ -	$ 83,582	$ -	$ -	$ -	$ 83,582
40	[redacted]	$ -	$ -	$ 87,505	$ -	$ -	$ -	$ 87,505
41	[redacted]	$ -	$ -	$ -	$ -	$ 64,242	$ -	$ 64,242
42	[redacted]	$ -	$ 9,798	$ 26,250	$ -	$ -	$ -	$ 36,048
43	[redacted]	$ -	$ -	$ -	$ 208,028	$ 1,826,717	$ 439,647	$ 2,474,392
44	[redacted]	$ -	$ -	$ 490	$ -	$ -	$ -	$ 490
45	[redacted]	$ -	$ -	$ -	$ 20,000	$ (10,000) (a)	$ -	$ 10,000
46	[redacted]	$ -	$ -	$ -	$ 2,438	$ -	$ -	$ 2,438
47	[redacted]	$ -	$ -	$ 2,000	$ 7,694	$ -	$ -	$ 9,694
48	[redacted]	$ -	$ -	$ 104,373	$ 205,712	$ 88,216	$ 1,845	$ 400,146
49	[redacted]	$ -	$ -	$ 12,250	$ -	$ -	$ -	$ 12,250
50	[redacted]	$ -	$ -	$ -	$ 7,447	$ -	$ -	$ 7,447
51	[redacted]	$ -	$ -	$ 139,875	$ -	$ -	$ -	$ 139,875
52	[redacted]	$ -	$ -	$ 189,489	$ 184,948	$ -	$ -	$ 374,437

Eversource Energy Service Company
Other Transition Costs Exhibit

	(A) Company	Costs (B) 2010		(C) 2011		(D) 2012		(E) 2013		(F) 2014		(G) 2015		(H)= (B)+(C)+(D)+(E)+(F)+(G) Total
53	[redacted]	$ -		$ -		$ -		$ 27,986		$ -		$ -		$ 27,986
54		$ -		$ 49,000		$ -		$ -		$ -		$ -		$ 49,000
55		$ -		$ -		$ -		$ 63,000		$ -		$ -		$ 63,000
56		$ -		$ -		$ -		$ -		$ 491		$ -		$ 491
57		$ -		$ -		$ 6,724		$ -		$ -		$ -		$ 6,724
	Total (Sum Ln 1 - Ln 57)	$ 170,000	(b)	$ 3,359,651	(b)	$ 1,965,610	(c)	$ 1,511,505	(b)	$ 2,651,823	(b)	$ 854,899	(b)	$ 10,513,488

(a) Negative costs are due to the reversal of unvouchered liabilities and journal entries.
(b) Exhibit No. ES-103, Page 47, Line 9.
(c) The Merger Integration Report, Exhibit No. ES-103, page 47, line 9 included a write off of fees associated with the termination of existing revolving credit agreements in the amount of $1.3 M.
This fee is excluded from this Exhibit because it was recorded to FERC Account No. 431 which is not included in Eversource Companies' formula rates.

See Exhibit ES-212, Pages 3 and 4 for a description of the vendor's Scope of Work.

Eversource Energy Service Company
Other Transition Cost Exhibit

	Vendor	Scope of Work
1	[redacted]	
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Eversource Energy Service Company
Other Transition Cost Exhibit

	Company	Scope of Summary
53	[redacted]	
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Exhibit No. ES-213

Separation Costs - Separation Assistance Exhibit

Eversource Energy Service Company

Eversource Energy Service Company
Separation Costs - Separation Assistance Exhibit

		Costs	
	(A)	(B)	
	Company	2012	
1	[redacted]	$ 162,000	(a)

[redacted]

(a) Exhibit No. ES-103, Page 47, Line 4.

Exhibit No. ES-214
Schedule 1

Summary of Impact on CL&P's, PNSH's, and WMECO's PTF Revenue Requirements under Attachment F of ISO-NE OATT (1-year amortization)

Eversource Energy Service Company

CL&P, PSNH, and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirement Comparison Under Present and Changed Rates
Under Attachment F of the ISO-NE OATT
For the Calendar Year 2016

Line	(A) Description	(B) Total Attachment F Revenue Requirements under Present Rates	(C) Total Attachment F Revenue Requirements under Changed Rates	(D) = (C) - (B) Difference	(E) = (D) / (B) % Difference
1	2016 Estimated PTF Revenue Requirement	$ 767,938,495 (1)	$ 792,301,975 (2)	$ 24,363,000 (3)	3.2%

Notes:

(1) Exhibit No. ES-214, Schedule 2, Page 1 of 20, Line 10(F)

(2) Exhibit No. ES-214, Schedule 3, Page 1 of 20, Line 10(F)

(3) In connection with the one-year amortization proposal (with the proposed effective date of June 1, 2016), Eversource is showing the revenue impact for the twelve-month period June 1, 2016 through May 31, 2017. Eversource is using revenue requirement calculations for the calendar year 2016 as an estimate for the twelve-month period beginning June 1, 2016. See Cooper Testimony Exhibit No. ES-200.

	2016	2017	Total
The amounts for each year are as follows:	$ 14,211,750	$ 10,151,250	$ 24,363,000

Exhibit No. ES-214
Schedule 2

CL&P's, PSNH's and WMECO's PTF Revenue Requirements under the Present Rates

Eversource Energy Service Company

CL&P, PSNH, and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Present Rates
Under Attachment F of the ISO-NE OATT
For the Calendar Year 2016

Line	(A) Description	(B) Reference	(C) CL&P		(D) PSNH		(E) WMECO		(F)=(C)+(D)+(E) Total
1	2014 Actual PTF Revenue Requirements		$ 454,159,787	(1)	$ 107,956,641	(2)	$ 110,031,567	(3)	$ 672,147,995
2	Estimated 2015 PTF Plant Additions	(4)	$ 276,000,000		$ 114,000,000		$ 87,000,000		$ 477,000,000
3	Carrying Charge Factor (CCF)	Exhibit No. ES-214, Schedule 2, Page 3 of 20, Note (3)	15.25%		16.55%		14.00%		
4	2015 Incremental Estimated PTF Revenue Requirements	Line 2 x 3	42,090,000		18,867,000		12,180,000		$ 73,137,000
5	2015 Incremental Estimated PTF CWIP Rev. Req.	(4)	$ (19,400,000)		$ -		$ -		$ (19,400,000)
6	Total Estimated PTF Revenue Requirement for 2015	Line 1 + 4 + 5	$ 476,849,787		$ 126,823,641		$ 122,211,567		$ 725,884,995
7	Estimated 2016 PTF Plant Additions	(4)	$ 68,000,000		$ 117,000,000		$ 88,000,000		$ 273,000,000
8	Carrying Charge Factor (CCF)	Line 3	15.25%		16.55%		14.00%		
9	2016 Incremental Estimated PTF Revenue Requirements	Line 7 x 8	10,370,000		19,363,500		12,320,000		$ 42,053,500
10	Total Estimated PTF Revenue Requirement for 2016	Line 6 + 9	$ 487,219,787		$ 146,187,141		$ 134,531,567		$ 767,938,495

Notes:
(1) Exhibit No. ES-214: Schedule 2, Page 2 of 20, LN. 29(B) + Schedule 2, Page 3 of 20, LN. 29(B) + Schedule 2, Page 4 of 20, LN. 5(B) + Schedule 2, Page 5 of 20, LN. 9(B)
(2) Exhibit No. ES-214: Schedule 2, Page 2 of 20, LN. 29(C) + Schedule 2, Page 3 of 20, LN. 29(C) + Schedule 2, Page 4 of 20, LN. 5(C)
(3) Exhibit No. ES-214: Schedule 2, Page 2 of 20, LN. 29(D) + Schedule 2, Page 3 of 20, LN. 29(D) + Schedule 2, Page 4 of 20, LN. 5(D) + Schedule 2, Page 5 of 20, LN. 9(C)
(4) Based on Eversource's Forecast

CL&P, PSNH, and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Present Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Pre-1997
Worksheet 1A

Line		(A)	Attachment F Reference Section:	(B) CL&P	(C) PSNH	(D) WMECO	(E)=(B)+(C)+(D) Total	(F) Reference	(G) Notes
	I.	INVESTMENT BASE							
1		Transmission Plant	(A)(1)(a)	358,812,326	88,564,672	53,145,202	500,522,200	W/S 3A,3B,3C line 1	(1)
2		General Plant	(A)(1)(b)	12,027,048	7,336,167	1,150,391	20,513,606	W/S 3A,3B,3C line 2	(1)
3		Plant Held For Future Use	(A)(1)(c)	84,157	1,138,376	0	1,222,533	W/S 3A,3B,3C line 4	(1)
4		Total Plant (Lines 1+2+3)		370,923,531	97,039,215	54,295,593	522,258,339		(1)
5		Accumulated Depreciation	(A)(1)(d)	73,042,167	17,223,185	3,590,105	93,855,457	W/S 3A,3B,3C line 7	(1)
6		Accumulated Deferred Income Taxes	(A)(1)(e)	49,105,827	16,884,906	13,484,433	79,475,166	W/S 3A,3B,3C line 10	(1)
7		Loss On Reacquired Debt	(A)(1)(f)	623,759	245,415	20,268	889,442	W/S 3A,3B,3C line 11	(1)
8		Other Regulatory Assets	(A)(1)(g)	2,278,427	1,052,873	568,906	3,900,206	W/S 3A,3B,3C line 15	(1)
9		Net Investment (Line 4-5-6+7+8)		251,677,723	64,229,412	37,810,229	353,717,364		(1)
10		Prepayments	(A)(1)(h)	1,885,610	662,602	62,672	2,610,884	W/S 3A,3B,3C line 16	(1)
11		Materials & Supplies	(A)(1)(i)	4,547,780	1,261,158	192,426	6,001,364	W/S 3A,3B,3C line 17	(1)
12		Cash Working Capital	(A)(1)(j)	1,080,762	381,944	154,988	1,617,694	W/S 3A,3B,3C line 23	(2)
13		Total Investment Base (Line 9+10+11+12)		259,191,875	66,535,116	38,220,315	363,947,306		(2)
	II.	REVENUE REQUIREMENTS							
14		Investment Return and Income Taxes	(A)	32,224,548	7,926,262	4,390,482	44,541,292	W/S 2A,2B,2C line 15	(2)
15		Depreciation Expense	(B)	8,594,771	1,919,255	1,026,040	11,540,066	W/S 4A,4B,4C line 3	(1)
16		Amortization of Loss on Reacquired Debt	(C)	68,393	30,531	3,040	101,964	W/S 4A,4B,4C line 4	(1)
17		Investment Tax Credit	(D)	(49,341)	(600)	(2,179)	(52,120)	W/S 4A,4B,4C line 5	(1)
18		Property Tax Expense	(E)	5,226,750	2,236,785	1,145,707	8,609,242	W/S 4A,4B,4C line 8	(1)
19		Payroll Tax Expense	(F)	37,155	(505)	1,120	37,770	W/S 4A,4B,4C line 18	(1)
20		Operation & Maintenance Expense	(G)	4,360,357	1,271,570	389,810	6,021,737	W/S 4A,4B,4C line 16	(1)
21		Administrative & General Expense	(H)	4,285,741	1,279,710	492,228	6,057,679	W/S 4A,4B,4C line 17	(2)
22		Transmission Related Integrated Facilities Charge	(I)	-	-	-	-	N/A	(1)
23		Transmission Support Revenue	(J)	(2,917,925)	(376,198)	-	(3,294,123)	W/S 7	(1)
24		Transmission Support Expense	(K)	1,625,568	880,469	357,869	2,863,906	W/S 7	(1)
25		Transmission Related Expense from Generators	(L)	-	-	-	-	N/A	(1)
26		Transmission Related Taxes and Fees Charge	(M)	1,135,268	19,553	1,263	1,156,084	Attachment B, line 14	(1)
27		Revenue for ST Trans. Service Under the OATT	(N)	(68,394)	(16,040)	(8,880)	(93,314)	Attachment C, line 9	(1)
28		Transmission Rents Received from Electric Property	(O)	(5,239,993)	(1,821,957)	(402,030)	(7,463,980)	Attachment C1, line 3	(1)
29		Total Revenue Requirements (Line 14 thru 28)		49,282,898	13,348,835	7,394,470	70,026,203		(2)

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
Provided this support because these balances will be revised under the changed rates.

CL&P, PSNH, and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Present Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Post-1996
Worksheet 1B

Line	(A)	Attachment F Reference Section:	(B) CL&P	(C) PSNH	(D) WMECO	(E)=(B)+(C)+(D) Total	(F) Reference	(G) Notes
	I. INVESTMENT BASE							
1	Transmission Plant	(A)(1)(a)	2,415,403,244	568,289,707	717,553,491	3,701,246,442	W/S 3A,3B,3C line 1	(1)
2	General Plant	(A)(1)(b)	80,962,316	47,073,591	15,532,275	143,568,182	W/S 3A,3B,3C line 2	(1)
3	Plant Held For Future Use	(A)(1)(c)	566,521	7,304,557	-	7,871,078	W/S 3A,3B,3C line 4	(1)
4	Total Plant (Lines 1+2+3)		2,496,932,081	622,667,855	733,085,766	3,852,685,702		(1)
5	Accumulated Depreciation	(A)(1)(d)	491,696,956	110,515,089	48,472,669	650,684,714	W/S 3A,3B,3C line 7	(1)
6	Accumulated Deferred Income Taxes	(A)(1)(e)	330,565,024	108,344,471	182,063,297	620,972,792	W/S 3A,3B,3C line 10	(1)
7	Loss On Reacquired Debt	(A)(1)(f)	4,198,950	1,574,739	273,655	6,047,344	W/S 3A,3B,3C line 11	(1)
8	Other Regulatory Assets	(A)(1)(g)	15,337,661	6,755,912	7,681,218	29,774,791	W/S 3A,3B,3C line 15	(1)
9	Net Investment (Line 4-5-6+7+8)		1,694,206,712	412,138,946	510,504,673	2,616,850,331		(1)
10	Prepayments	(A)(1)(h)	12,693,335	4,251,680	846,180	17,791,195	W/S 3A,3B,3C line 16	(1)
11	Materials & Supplies	(A)(1)(i)	30,614,229	8,092,403	2,598,082	41,304,714	W/S 3A,3B,3C line 17	(1)
12	Cash Working Capital	(A)(1)(j)	7,275,352	2,046,333	1,488,631	10,810,316	W/S 3A,3B,3C line 23	(2)
13	Total Investment Base Excluding CWIP (Line 9+10+11+12)		1,744,789,628	426,529,362	515,437,566	2,686,756,556		(2)
14	NEEWS Construction Work In Progress	(A)(1)(l)	164,948,530		-	164,948,530	(a)	(1)
15	Total Investment Base Including CWIP (Line 13+14)		1,909,738,158	426,529,362	515,437,566	2,851,705,086		(2)
	II. REVENUE REQUIREMENTS							
16	Investment Return and Income Taxes	(A)	216,835,476	50,812,016	59,209,860	326,857,352	W/S 2A,2B,2C line 15	(2)
17	Investment Return and Income Taxes-CWIP		20,499,144	-	-	20,499,144	W/S 2A,2B,2C line 15	(1)
18	Depreciation Expense	(B)	57,857,303	12,315,183	13,853,324	84,025,810	W/S 4A,4B,4C line 3	(1)
19	Amortization of Loss on Reacquired Debt	(C)	460,401	195,905	41,048	697,354	W/S 4A,4B,4C line 4	(1)
20	Investment Tax Credit	(D)	(332,148)	(3,850)	(29,425)	(365,423)	W/S 4A,4B,4C line 5	(1)
21	Property Tax Expense	(E)	35,184,843	14,352,660	15,469,033	65,006,536	W/S 4A,4B,4C line 8	(1)
22	Payroll Tax Expense	(F)	250,119	(3,240)	15,117	261,996	W/S 4A,4B,4C line 18	(1)
23	Operation & Maintenance Expense	(G)	29,352,552	8,159,213	5,263,108	42,774,873	W/S 4A,4B,4C line 16	(1)
24	Administrative & General Expense	(H)	28,850,267	8,211,448	6,645,940	43,707,655	W/S 4A,4B,4C line 17	(2)
25	Transmission Related Integrated Facilities Charge	(I)	-	-	-	-	N/A	(1)
26	Transmission Related Expense from Generators	(L)	-	-	-	-	N/A	(1)
27	Transmission Related Taxes and Fees Charge	(M)	7,642,269	125,466	17,047	7,784,782	Attachment B line 16	(1)
28	Revenue for ST Trans. Service Under the OATT	(N)	(460,565)	(102,948)	(119,820)	(683,333)	Attachment C line 10	(1)
29	Total Revenue Requirements (Line 16 thru 28)		396,139,661	94,061,853	100,365,232	590,566,746		(2)

(a) Reflects actual information per Eversource's accounting records

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
Provided this support because these balances will be revised under the changed rates.

		CL&P	PSNH	WMECO
(3)	**Carrying Charge Factor** (Line (16+ 18 thru 24) / Line 1)	15.25%	16.55%	14.00%

CL&P, PSNH, and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Present Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Post-2003
Worksheet 1C

Line	(A) I. INVESTMENT BASE	(B) CL&P	(C) PSNH	(D) WMECO	(E)=(B)+(C)+(D) TOTAL	(F) Reference	(G) Notes
1	Transmission Plant	$ 1,535,579,816	$ 124,215,608	$ 12,384,353	$ 1,672,179,777	Attachment D, D2, D4	(1)
2	Accumulated Depreciation	$ 213,218,089	$ 18,074,549	$ 1,442,093	$ 232,734,731	Attachment D, D2, D4	(1)
3	Accumulated Deferred Income Taxes	$ 155,340,565	$ 15,930,789	$ 2,675,475	$ 173,946,829	Attachment D1, D3, D5	(1)
4	Net Investment (Line 1-2-3)	$ 1,167,021,162	$ 90,210,270	$ 8,266,785	$ 1,265,498,217		(1)
	II. INCREMENTAL RETURN						
5	Incremental Revenue Requirements	$ 6,906,431	$ 545,953	$ 47,005	$ 7,499,389	W/S 2A,2B,2C Post 2003	(1)

Note: ROE incentives approved in FERC Opinion No. 489. As a result of Opinion No. 531-B, these projects receive an ROE incentive of 67 bp.

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.

CL&P, PSNH, and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Present Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
NEEWS
Worksheet 1E

Line	(A)	(B) CL&P	(C) WMECO	(D) = (B) + (C) Total	(E) Reference	(F) Notes
	I. INVESTMENT BASE					
1	Transmission Plant	$ 200,288,632	$ 556,313,751	$ 756,602,383	Attachment F & F2	(1)
2	Accumulated Depreciation	$ 8,946,318	$ 22,283,705	$ 31,230,023	Attachment F & F2	(1)
3	Accumulated Deferred Income Taxes	$ 46,929,968	$ 142,742,742	$ 189,672,710	Attachment F1 & F3	(1)
4	Net Investment Excluding CWIP(Line 1-2-3)	$ 144,412,346	$ 391,287,304	$ 535,699,650		(1)
5	NEEWS Construction Work In Progress	$ 164,948,530	$ -	$ 164,948,530	Attachment F & F2	(1)
6	Net Investment Including CWIP(Line 4+5)	$ 309,360,876	$ 391,287,304	$ 700,648,180		(1)
	II. INCREMENTAL RETURN					
7	Incremental Revenue Requirements	$ 854,632	$ 2,224,860	$ 3,079,492	W/S 2A & 2C NEEWS	(1)
8	Incremental Revenue Requirements-CWIP	$ 976,165	$ -	$ 976,165	W/S 2A & 2C NEEWS	(1)
9	Total Incremental Revenue Requirements (line 7+8)	$ 1,830,797	$ 2,224,860	$ 4,055,657		(1)

Note: Incentives approved in FERC Docket No. ER08-1548. As a result of Opinion No. 531-B, this project receives ROE incentives of 67 bp.

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.

Connecticut Light & Power Company (CL&P)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Present Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Investment Return and Income Taxes - Pre 1997
Worksheet 2A

Line	(A)	(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 2,579,060,322	45.78%	5.36%	2.45%		
2	PREFERRED STOCK	$ 116,868,097	2.07%	4.80%	0.10%	0.10%	
3	COMMON EQUITY	$ 2,938,441,767	52.15%	11.07%	5.77%	5.77%	
4	TOTAL INVESTMENT RETURN	$ 5,634,370,186	100.00%		8.32%	5.87%	

Cost of Capital Rate=

Line											
5	(a) Weighted Cost of Capital	=	0.0832								
	(b) Federal Income Tax	= (	R.O.E. +	(	PTF Inv. (Tax Credit (W/S 1A)	+	Eq. AFUDC of Deprec. Exp. (Att. I)	) /	PTF Inv. Base (W/S 1A)	x	Federal Income Tax Rate)
							(1 - Federal Income Tax Rate)				
6		=	0.0587	+(	(49,341)	+	269,748	) /	259,191,875	) x	0.35)
7							(1	-	0.35	)	
8		=	0.032066								
	(c) State Income Tax	=	R.O.E. +	(	PTF Inv. (Tax Credit	+	Eq. AFUDC of Deprec. Exp.	) /	PTF Inv. Base)	+	Federal Income Tax)*State Income Tax Rate
							(1 - State Income tax Rate)				
9		=	0.0587	+(	(49,341)	+	269,748	) /	259,191,875	) +	0.032066)* 0.09
10							(1	-	0.09	)	
11		=	0.009061								
12	(a)+(b)+(c) **Cost of Capital Rate**	=	0.124327								

Line		Pre-1997 PTF	
13	INVESTMENT BASE	$ 259,191,875	From Worksheet 1A, line 13
14	x Cost of Capital Rate	0.124327	
15	= Investment Return and Income Taxes	$ 32,224,548	To Worksheet 1A, line 14

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Provided this support because the balance in "Total Inv. Base" will be revised under the Changed Rates

Connecticut Light & Power Company (CL&P)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Present Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Investment Return and Income Taxes - Post 1996
Worksheet 2A

Line	(A)	(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 2,579,060,322	45.78%	5.36%	2.45%		
2	PREFERRED STOCK	$ 116,868,097	2.07%	4.80%	0.10%	0.10%	
3	COMMON EQUITY	$ 2,938,441,767	52.15%	11.07%	5.77%	5.77%	
4	TOTAL INVESTMENT RETURN	$ 5,634,370,186	100.00%		8.32%	5.87%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.0832

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit (W/S 1B) + Eq. AFUDC of Deprec. Exp. (Att. I)) / PTF Inv. Base (W/S 1B) x Federal Income Tax Rate)
(1 - Federal Income Tax Rate)

6 = 0.0587 +((332,148) + 1,815,862) / 1,909,738,158) x 0.35)
7 (1 - 0.35)

8 = 0.032026

(c) State Income Tax = R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate
(1 - State Income tax Rate)

9 = 0.0587 +((332,148) + 1,815,862) / 1,909,738,158) + 0.032026)* 0.09
10 (1 - 0.09)

11 = 0.009050

12 (a)+(b)+(c) Cost of Capital Rate = 0.124276

Line		Post - 1996 Total PTF	-	Post - 1996 PTF CWIP	=	Post -1996 PTF Excluding CWIP	
13	INVESTMENT BASE	$ 1,909,738,158		$ 164,948,530		$ 1,744,789,628	From Worksheet 1B, line 13, 14
14	x Cost of Capital Rate	0.124276		0.124276		0.124276	
15	= Investment Return and Income Taxes	$ 237,334,619		$ 20,499,144		$ 216,835,476	To Worksheet 1B, line 16

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Provided this support because the balance in "Total Inv. Base" will be revised under the Changed Rates

Connecticut Light & Power Company (CL&P)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Present Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Investment Return and Income Taxes - 50bp

Line	(A)	(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 2,579,060,322	45.78%		0.00%		
2	PREFERRED STOCK	$ 116,868,097	2.07%		0.00%	0.00%	
3	COMMON EQUITY	$ 2,938,441,767	52.15%	0.50%	0.26%	0.26%	
4	TOTAL INVESTMENT RETURN	$ 5,634,370,186	100.00%		0.26%	0.26%	

Cost of Capital Rate=

Line											
5	(a) Weighted Cost of Capital	=	0.0026								
	(b) Federal Income Tax	= (	R.O.E. +	(	PTF Inv. (Tax Credit (W/S 1B)	+	Eq. AFUDC of Deprec. Exp. (Att. I)	) /	PTF Inv. Base (W/S 1B)	x	Federal Income Tax Rate)
							(1 - Federal Income Tax Rate)				
6		=	0.0026	+(	0	+	0	) /	2,168,930,033	) x	0.35)
7						(	1	-	0.35	)	
8		=	0.001400								
	(c) State Income Tax	=	R.O.E. +	(	PTF Inv. (Tax Credit	+	Eq. AFUDC of Deprec. Exp.	) /	PTF Inv. Base)	+	Federal Income Tax)*State Income Tax Rate
							(1 - State Income tax Rate)				
9		=	0.0026	+(	0	+	0	) /	2,168,930,033	) +	0.001400)* 0.09
10						(	1	-	0.09	)	
11		=	0.000396								
12	(a)+(b)+(c) Cost of Capital Rate	=	0.004396								

Line		Total PTF
13	INVESTMENT BASE	$ 2,168,930,033
14	x Cost of Capital Rate	0.004396
15	= Investment Return and Income Taxes	$ 9,534,616

Notes:

(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-217, Schedule 1, Page 2 of 2
(2) Provided this support because the balance in "Total Inv. Base" will be revised under the Changed Rates

Connecticut Light & Power Company (CL&P)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Present Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Worksheet 3A

					Pre-1997 PTF		**Post-1996 PTF**			
		(1)	(2) Wage/Plant Allocation	(3)	(4) PTF Allocation	(5) = (3)*(4) PTF	(6) PTF Allocation	(7) = (3)*(6) PTF		
LN.		Transmission	Factors (a)	Transmission	Factor (b)	Allocated	Factor (b)	Allocated	Reference	Notes
	Transmission Plant									
1	Transmission Plant					358,812,326		2,415,403,244	Attachment A (H1)	(1)
2	General Plant	104,400,554		104,400,554	11.5201%	12,027,048	77.5497%	80,962,316	FF1 page 204 ln. 99, footnote	(1)
3	Total (line 1+2)	104,400,554		104,400,554		370,839,374		2,496,365,560		(1)
										(1)
4	Transmission Plant Held for Future Use	730,526 (c)		730,526	11.5201%	84,157	77.5497%	566,521	(c)	(1)
	Transmission Accumulated Depreciation									
5	Transmission Accum. Depreciation	605,238,764		605,238,764	11.5201%	69,724,111	77.5497%	469,360,846	FF1 page 219 ln. 25	(1)
6	General Plant Accum. Depreciation	28,802,317		28,802,317	11.5201%	3,318,056	77.5497%	22,336,110	FF1 page 219 ln. 28, footnote	(1)
7	Total (line 5+6)	634,041,081		634,041,081		73,042,167		491,696,956	Schedule 2, Page 6,7,8	(1)
	Transmission Accumulated Deferred Taxes									
8	Accumulated Deferred Taxes (281 to 283)	(470,775,688)		(470,775,688)	11.5201%	(54,233,830)	77.5497%	(365,085,134)	FF1 page 274 ln. 9 & 276 ln. 19 fns	(1)
9	Accumulated Deferred Taxes (190)	44,513,531 (d)		44,513,531	11.5201%	5,128,003	77.5497%	34,520,110	(d)	(1)
10	Total (line 8+9)	(426,262,157)		(426,262,157)		(49,105,827)		(330,565,024)		(1)
11	Transmission loss on Reacquired Debt	5,414,528		5,414,528	11.5201%	623,759	77.5497%	4,198,950	FF1 page 110 ln. 81, footnote	(1)
	Other Regulatory Assets									
12	FAS 106	66,791		66,791	11.5201%	7,694	77.5497%	51,796	FF1 page 232 Ln. 27, footnote	(1)
13	FAS 109	23,019,567		23,019,567	11.5201%	2,651,877	77.5497%	17,851,605	FF1 page 232 ln. 7, footnote	(1)
14	Other Regulatory Liabilities (254.DK)	(3,308,510)		(3,308,510)	11.5201%	(381,144)	77.5497%	(2,565,740)	FF1 page 278 ln. 3, footnote	(1)
15	Total (line 12+13+14)	19,777,848		19,777,848		2,278,427		15,337,661		(1)
16	Transmission Prepayments (165)	16,368,000		16,368,000	11.5201%	1,885,610	77.5497%	12,693,335	FF1 page 110 ln. 57, footnote	(1)
17	Transmission Materials and Supplies	39,476,915		39,476,915	11.5201%	4,547,780	77.5497%	30,614,229	FF1 page 227 ln. 8	(1)
	Cash Working Capital									
18	Operation & Maintenance Expense					4,360,357		29,352,552	W/S 4A, Line 16	(1)
19	Administrative & General Expense					4,285,741		28,850,267	W/S 4A, Line 17	(2)
20	Transmission Support Expense					-		-	W/S 7	(1)
21	Subtotal (line 18+19+20)					8,646,098		58,202,819		(2)
22						0.125		0.125	x 45 / 360	(1)
23	Total (line 21 * line 22)					1,080,762		7,275,352		(2)

(a) All items are specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries and Plant Allocation Factors are not used (column 2

(b) W/S 5A & 5B

(c)	Account 105	32,127,498	FF1 page 214 ln. 33	(1)
	Less Third Underground Conduit Duct	31,396,972	FF1 page 214 ln. 22	(1)
		730,526		(1)
(d)	Account 190	46,955,376	FF1 page 234 ln. 18, footnote	(1)
	Less Reserve for Disputed Transactions	2,441,845	FF1 page 234 ln. 18, footnote	(1)
	Total Account 190	44,513,531		(1)

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
Provided this support because these balances will be revised under the changed rates.

Connecticut Light & Power Company (CL&P)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Present Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Worksheet 4A

					PRE-97 PTF		POST-96 PTF			
		(1)	(2)	(3)	(4)	(5) = (3)*(4)	(6)	(7) = (3)*(6)		
LN.		Transmission	Wage/Plant Allocation Factors (a)	Transmission	PTF Allocation Factor (b)	PTF Allocated	PTF Allocation Factor (b)	Post-96 PTF Allocated	Reference	Notes
	Depreciation Expense									
1	Transmission Depreciation	69,626,166		69,626,166	11.5201%	8,021,004	77.5497%	53,994,883	FF1 page 336 ln. 7	(1)
2	General Depreciation	4,980,574		4,980,574	11.5201%	573,767	77.5497%	3,862,420	FF1 page 336 ln. 10, footnote	(1)
3	Total (line 1+2)	74,606,740		74,606,740		8,594,771		57,857,303		(1)
4	Amortization of Loss on Reacquired Debt	593,685		593,685	11.5201%	68,393	77.5497%	460,401	FF1 page 114 ln. 64, footnote	(1)
5	Amortization of Investment Tax Credits	428,304		428,304	11.5201%	49,341	77.5497%	332,148	FF1 page 266 ln. 8(f), footnote	(1)
	Property Taxes									
6	Transmission Property Taxes	45,370,701		45,370,701	11.5201%	5,226,750	77.5497%	35,184,843	FF1 page 262 ln. 25i, footnote	(1)
7	General Property Taxes (c)	-		-	11.5201%	-	77.5497%	-		(1)
8	Total (line 6+7)	45,370,701		45,370,701		5,226,750		35,184,843		(1)
	Transmission Operation and Maintenance									
9	Operation and Maintenance	77,432,007		77,432,007	11.5201%	8,920,245	77.5497%	60,048,289	FF1 page 321 ln. 112	(1)
10	Transmission of Electricity by Others - #565	21,727,966		21,727,966	11.5201%	2,503,083	77.5497%	16,849,972	FF1 page 321 ln. 96	(1)
11	Account 561.1	3,245,594		3,245,594	11.5201%	373,896	77.5497%	2,516,948	FF1 page 321 ln. 85	(1)
12	Account 561.2	5,212,556		5,212,556	11.5201%	600,492	77.5497%	4,042,322	FF1 page 321 ln. 86	(1)
13	Account 561.3	2,238,612		2,238,612	11.5201%	257,890	77.5497%	1,736,037	FF1 page 321 ln. 87	(1)
14	Account 561.4	7,157,291		7,157,291	11.5201%	824,527	77.5497%	5,550,458	FF1 page 321 ln. 88	(1)
15	**Station Expenses & Rents	-		-	11.5201%	-	77.5497%	-	FF1 page 321 ln. 93 + ln. 98	(1)
16	O&M less lines 10 thru 15	37,849,988		37,849,988		4,360,357		29,352,552		(1)
	Transmission Administrative and General									
17	Administrative and General	37,202,294		37,202,294	11.5201%	4,285,741	77.5497%	28,850,267	FF1 page 320 ln. 197 b, footnote	(2)
18	*Payroll Tax Expense*	322,527		322,527	11.5201%	37,155	77.5497%	250,119		(1)
	Federal Unemployment	5,226							FF1 page 262 ln. 3i, footnote	(1)
	FICA	233,351							FF1 page 262 ln. 5i, footnote	(1)
	Medicare	65,613							FF1 page 262 ln. 9i, footnote	(1)
	CT Unemployment	16,786							FF1 page 262 ln. 15i, footnote	(1)
	DC Unemployment	11							FF1 page 262.1 ln. 14i, footnote	(1)
	FL Unemployment	1							FF1 page 262.1 ln. 18i, footnote	(1)
	GA Unemployment	-							FF1 page 262 footnote	(1)
	MA Unemployment	(285)							FF1 page 262 ln. 32i, footnote	(1)
	MA Universal Health	64							FF1 page 262 ln. 33i, footnote	(1)
	MI Unemployment	6							FF1 page 262.1 ln. 22i, footnote	(1)
	NH Unemployment	1,754							FF1 page 262.1 ln. 4i, footnote	(1)
	NJ Unemployment	-							FF1 page 262 footnote	(1)
	NY Unemployment	-							FF1 page 262.1 ln. 10i, footnote	(1)
	Total	322,527	To Line 18							(1)

** To the extent that PTF Support Payments are reflected in worksheet 7 they will be excluded from this calculation.
(a) All items are specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries and Plant Allocation Factors are not used (column 2).
(b) W/S 5A & 5B
(c) Transmission related general property taxes are included in the Transmission Property tax number footnoted in the FF1.

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000. Provided this support because these balances will be revised under the changed rates.

Public Service Company of New Hampshire (PSNH)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Present Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Investment Return and Income Taxes - Pre 1997
Worksheet 2B

Line	(A)	(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 1,070,020,120	46.56%	4.15%	1.93%		
2	PREFERRED STOCK	$ -	0.00%	0.00%	0.00%	0.00%	
3	COMMON EQUITY	$ 1,228,095,985	53.44%	11.07%	5.92%	5.92%	
4	TOTAL INVESTMENT RETURN	$ 2,298,116,105	100.00%		7.85%	5.92%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.0785

(b) Federal Income Tax =((R.O.E. + (PTF Inv. (Tax Credit (W/S 1A) + Eq. AFUDC of Deprec. Exp. (Att. I)) / PTF Inv. Base (W/S 1A) x Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

6 =(0.0592 +((600) + 29,005) / 66,535,116) x 0.35)
7 (1 - 0.35)

8 = 0.032107

(c) State Income Tax =(R.O.E. + +(PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate / (1 - State Income Tax Rate)

9 =(0.0592 +((600) + 29,005) / 66,535,116) + 0.032107)* 0.085
10 (1 - 0.085)

11 = 0.008522

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.119129

Line		**Pre-1997 PTF**	
13	INVESTMENT BASE	$ 66,535,116	From Worksheet 1A, line 13
14	x Cost of Capital Rate	0.1191290	
15	= Investment Return and Income Taxes	$ 7,926,262	To Worksheet 1A, line 14

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Provided this support because the balance in "Total Inv. Base" will be revised under the Changed Rates

Public Service Company of New Hampshire (PSNH)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Present Rates
For Costs in 2014
Investment Return and Income Taxes - Post 1996
Worksheet 2B

Line	(A)	(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 1,070,020,120	46.56%	4.15%	1.93%		
2	PREFERRED STOCK	$ -	0.00%	0.00%	0.00%	0.00%	
3	COMMON EQUITY	$ 1,228,095,985	53.44%	11.07%	5.92%	5.92%	
4	TOTAL INVESTMENT RETURN	$ 2,298,116,105	100.00%		7.85%	5.92%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.0785

(b) Federal Income Tax = ((R.O.E. + (PTF Inv. (Tax Credit (W/S 1B) + Eq. AFUDC of Deprec. Exp. (Att. I)) / PTF Inv. Base (W/S 1A) x Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

6 = (0.0592 +((3,850) + 186,109) / 426,529,362) x 0.35)
7 (1 - 0.35)

8 = 0.032107

(c) State Income Tax = (R.O.E. + +(PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate / (1 - State Income Tax Rate)

9 = (0.0592 +((3,850) + 186,109) / 426,529,362) + 0.032107)* 0.085
10 (1 - 0.085)

11 = 0.008522

12 (a)+(b)+(c) Cost of Capital Rate = 0.119129

Line		Post - 1996 Total PTF	
13	INVESTMENT BASE	$ 426,529,362	From Worksheet 1A, line 13
14	x Cost of Capital Rate	0.119129	
15	= Investment Return and Income Taxes	$ 50,812,016	To Worksheet 1B, line 16

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Provided this support because the balance in "Total Inv. Base" will be revised under the Changed Rates

Public Service Company of New Hampshire (PSNH)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Present Rates
For Costs in 2014
Investment Return and Income Taxes - Post 1996
Investment Return and Income Taxes - 50bp

Line	(A)	(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 1,070,020,120	46.56%		0.00%		
2	PREFERRED STOCK	$ -	0.00%		0.00%	0.00%	
3	COMMON EQUITY	$ 1,228,095,985	53.44%	0.50%	0.27%	0.27%	
4	TOTAL INVESTMENT RETURN	$ 2,298,116,105	100.00%		0.27%	0.27%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.0027

(b) Federal Income Tax = ((R.O.E. + (PTF Inv. (Tax Credit (W/S 1B) + Eq. AFUDC of Deprec. Exp. (Att. I)) / PTF Inv. Base (W/S 1A) x Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

6 = (0.0027 +(0 + 0) / 493,064,478) x 0.35)
7 (1 - 0.35)

8 = 0.001454

(c) State Income Tax = (R.O.E. + +(PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate / (1 - State Income Tax Rate)

9 = (0.0027 +(0 + 0) / 493,064,478) + 0.001454)* 0.085
10 (1 - 0.085)

11 = 0.000386

12 (a)+(b)+(c) Cost of Capital Rate = 0.004540

Line		Total PTF
13	INVESTMENT BASE	$ 493,064,478
14	x Cost of Capital Rate	0.004540
15	= Investment Return and Income Taxes	$ 2,238,513

Notes:

(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-217, Schedule 1, Page 2 of 2
(2) Provided this support because the balance in "Total Inv. Base" will be revised under the Changed Rates

Public Service Company of New Hampshire (PSNH)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Present Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Worksheet 3B

					Pre-1997 PTF		Post-1996 PTF			
		(1)	(2)	(3)	(4)	(5) = (3)*(4)	(6)	(7) = (3)*(6)		
			Wage/Plant		PTF		PTF	Post-96		
			Allocation		Allocation	PTF	Allocation	PTF		
LN.		Transmission	Factors (a)	Transmission	Factor (b)	Allocated	Factor (b)	Allocated	Reference	Notes
	Transmission Plant									
1	Transmission Plant					88,564,672		568,289,707	Attachment A1	(1)
2	General Plant	59,322,426		59,322,426	12.3666%	7,336,167	79.3521%	47,073,591	FF1 page 204 ln. 99, footnote	(1)
3	Total (line 1+2)	59,322,426		59,322,426		95,900,839		615,363,298		(1)
										(1)
4	Transmission Plant Held for Future Use	9,205,247		9,205,247	12.3666%	1,138,376	79.3521%	7,304,557	FF1 page 214 ln. 35	(1)
	Transmission Accumulated Depreciation									
5	Transmission Accum. Depreciation	123,132,357		123,132,357	12.3666%	15,227,286	79.3521%	97,708,111	FF1 page 219 ln. 25	(1)
6	General Plant Accum. Depreciation	16,139,432		16,139,432	12.3666%	1,995,899	79.3521%	12,806,978	FF1 page 219 ln. 28, footnote	(1)
7	Total (line 5+6)	139,271,789		139,271,789		17,223,185		110,515,089		(1)
	Transmission Accumulated Deferred Taxes									
8	Accumulated Deferred Taxes (281-283)	(145,475,861)		(145,475,861)	12.3666%	(17,990,418)	79.3521%	(115,438,151)	FF1 page 274 ln. 9 & 276 ln. 19 fns	(1)
9	Accumulated Deferred Taxes (190)	8,939,499 (c)		8,939,499	12.3666%	1,105,512	79.3521%	7,093,680	(c)	(1)
10	Total (line 8+9)	(136,536,362)		(136,536,362)		(16,884,906)				
				-						
11	Transmission loss on Reacquired Debt	1,984,496		1,984,496	12.3666%	245,415	79.3521%	1,574,739	FF1 page 110 ln. 81, footnote	(1)
	Other Regulatory Assets									
12	FAS 106	350,591		350,591	12.3666%	43,356	79.3521%	278,201	FF1 page 232.1 ln. 15, footnote	(1)
13	FAS 109	8,171,016		8,171,016	12.3666%	1,010,477	79.3521%	6,483,873	FF1 page 232 ln. 1, footnote	(1)
14	Other Regulatory Liabilities (254.DK)	(7,765)		(7,765)	12.3666%	(960)	79.3521%	(6,162)	FF1 page 278 ln. 1, footnote	(1)
15	Total (line 12+13+14)	8,513,842		8,513,842		1,052,873		6,755,912		(1)
16	Transmission Prepayments	5,357,993		5,357,993	12.3666%	662,602	79.3521%	4,251,680	FF1 page 110 ln. 57, footnote	(1)
17	Transmission Materials and Supplies	10,198,096		10,198,096	12.3666%	1,261,158	79.3521%	8,092,403	FF1 page 227 ln. 8	(1)
	Cash Working Capital									
18	Operation & Maintenance Expense					1,271,570		8,159,213	W/S 4B, Line 16	(1)
19	Administrative & General Expense					1,279,710		8,211,448	W/S 4B, Line 17	(2)
20	Transmission Support Expense					504,271		-	W/S 7	(1)
21	Subtotal (line 18+19+20)					3,055,551		16,370,661		(2)
22						0.125		0.125	x 45 / 360	(1)
23	Total (line 21 * line 22)					381,944		2,046,333		(2)

(a) All items are specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries and Plant Allocation Factors are not used (column 2).
(b) W/S 5A & 5B
(c)

Account 190	8,939,499	FF1 page 234 ln. 18, footnote	(1)
Less Reserve for Disputed Transactions	-	FF1 page 234 ln. 18, footnote	(1)
Total Account 190	8,939,499		(1)

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000. Provided this support because these balances will be revised under the changed rates.

Public Service Company of New Hampshire (PSNH)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Present Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Worksheet 4B

LN.		(1) Transmission	(2) Wage/Plant Allocation Factors (a)	(3) Transmission	Pre-1997 PTF (4) PTF Allocation Factor (b)	Pre-1997 PTF (5) = (3)*(4) PTF Allocated	Post-1996 PTF (6) PTF Allocation Factor (b)	Post-1996 PTF (7) = (3)*(6) Post-96 PTF Allocated	Reference	Notes
	Depreciation Expense									
1	Transmission Depreciation	12,792,512		12,792,512	12.3666%	1,581,999	79.3521%	10,151,127	FF 1 page 336 ln. 7	(1)
2	General Depreciation	2,727,156		2,727,156	12.3666%	337,256	79.3521%	2,164,056	FF1 page 336 ln. 10, footnote	(1)
3	Total (line 1+2)	15,519,668		15,519,668		1,919,255		12,315,183		(1)
4	Amortization of Loss on Reacquired Debt	246,881		246,881	12.3666%	30,531	79.3521%	195,905	FF1 page 114 ln. 64, footnote	(1)
5	Amortization of Investment Tax Credits	4,852		4,852	12.3666%	600	79.3521%	3,850	FF1 page 266 ln. 8(f), footnote	(1)
	Property Taxes									
6	Transmission Property Taxes	18,087,310		18,087,310	12.3666%	2,236,785	79.3521%	14,352,660	FF1 page 262 ln. 23i + ln. 30i +	(1)
7	General Property Taxes (c)	-		-	12.3666%	-	79.3521%	-	page 262.1 ln. 2i, footnote	(1)
8	Total (line 6+7)	18,087,310		18,087,310		2,236,785		14,352,660		(1)
	Transmission Operation and Maintenance									
9	Operation and Maintenance	51,082,852		51,082,852	12.3666%	6,317,212	79.3521%	40,535,316	FF1 page 321 ln. 112	(1)
10	Transmission of Electricity by Others - #5	37,174,569		37,174,569	12.3666%	4,597,230	79.3521%	29,498,801	FF1 page 321 ln. 96	(1)
11	Account 561.1	653,575		653,575	12.3666%	80,825	79.3521%	518,625	FF1 page 321 ln. 85	(1)
12	Account 561.2	474,690		474,690	12.3666%	58,703	79.3521%	376,676	FF1 page 321 ln. 86	(1)
13	Account 561.3	36,962		36,962	12.3666%	4,571	79.3521%	29,330	FF1 page 321 ln. 87	(1)
14	Account 561.4	2,460,768		2,460,768	12.3666%	304,313	79.3521%	1,952,671	FF1 page 321 ln. 88	(1)
15	**Station Expenses & Rents	-		-	12.3666%	-	79.3521%	-	FF1 page 321 ln. 93 + ln. 98	(1)
16	O&M less lines 10 thru 15	10,282,288		10,282,288		1,271,570		8,159,213		(1)
	Transmission Administrative and General									
17	Administrative and General	10,348,117		10,348,117	12.3666%	1,279,710	79.3521%	8,211,448	FF1 page 320 ln. 197 b, footnote	(2)
18	*Payroll Tax Expense*	(4,083)		(4,083)	12.3666%	(505)	79.3521%	(3,240)		(1)
	Federal Unemployment	(51)							FF1 page 262 ln. 2i, footnote	(1)
	FICA	(3,062)							FF1 page 262 ln. 4i, footnote	(1)
	Medicare	(816)							FF1 page 262 ln. 7i, footnote	(1)
	CT Unemployment	(128)							FF1 page 262.1 ln. 7i, footnote	(1)
	DC Unemployment	0							FF1 page 262 ln. 26i, footnote	(1)
	FL Unemployment	0							FF1 page 262.1 ln. 27i, footnote	(1)
	GA Unemployment	0							FF1 page 262.1, footnote	(1)
	MA Unemployment	2							FF1 page 262.1 ln. 15i, footnote	(1)
	MA Universal Health	(1)							FF1 page 262.1 ln. 16i, footnote	(1)
	MI Unemployment	0							FF1 page 262.1 ln. 31i, footnote	(1)
	NH Unemployment	(27)							FF1 page 262 ln. 14i, footnote	(1)
	NJ Unemployment	0							FF1 page 262, footnote	(1)
	NY Unemployment	0							FF1 page 262 footnote	(1)
	Total	(4,083)	To Line 19							(1)

** To the extent that PTF Support Payments are reflected in worksheet 7 they will be excluded from this calculation.
(a) All items are specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries and Plant Allocation Factors are not used (column 2).
(b) W/S 5A & 5B
(c) Transmission related general property taxes are included in the Transmission Property tax number footnoted in the FF1.

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
Provided this support because these balances will be revised under the changed rates.

Western Massachusetts Electric Company (WMECO)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Present Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Investment Return and Income Taxes - Pre 1997
Worksheet 2C

Line	(A)	(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 567,833,428	49.55%	4.31%	2.14%		
2	PREFERRED STOCK	$ -	0.00%	0.00%	0.00%	0.00%	
3	COMMON EQUITY	$ 578,162,814	50.45%	11.07%	5.58%	5.58%	
4	TOTAL INVESTMENT RETURN	$ 1,145,996,242	100.00%		7.72%	5.58%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.0772

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit (W/S 1A) + Eq. AFUDC of Deprec. Exp. (Att. I)) / PTF Inv. Base (W/S 1A) x Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

6 = (0.0558 +((2,179) + 11,396) / 38,220,315) x 0.35)
7 (1 - 0.35)

8 = 0.030176

(c) State Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate / (1 - State Income Tax Rate)

9 = (0.0558 +((2,179) + 11,396) / 38,220,315) + 0.030176)* 0.08
10 (1 - 0.08)

11 = 0.007497

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.114873

Line		**Pre-1997 PTF**	
13	INVESTMENT BASE	$ 38,220,315	From Worksheet 1A, line 13
14	x Cost of Capital Rate	0.114873	
15	= Investment Return and Income Taxes	$ 4,390,482	To Worksheet 1A, line 14

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Provided this support because the balance in "Total Inv. Base" will be revised under the Changed Rates

Western Massachusetts Electric Company (WMECO)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Present Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014

Investment Return and Income Taxes - Post-1996

Worksheet 2C

Line	(A)	(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 567,833,428	49.55%	4.31%	2.14%		
2	PREFERRED STOCK	$ -	0.00%	0.00%	0.00%	0.00%	
3	COMMON EQUITY	$ 578,162,814	50.45%	11.07%	5.58%	5.58%	
4	TOTAL INVESTMENT RETURN	$ 1,145,996,242	100.00%		7.72%	5.58%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.0772

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit (W/S 1B) + Eq. AFUDC of Deprec. Exp. (Att. I)) / PTF Inv. Base (W/S 1B) x Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

6 = (0.0558 +((29,425) + 153,859) / 515,437,566) x 0.35)
7 (1 - 0.35)

8 = 0.030176

(c) State Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate / (1 - State Income Tax Rate)

9 = (0.0558 +((29,425) + 153,859) / 515,437,566) + 0.030176)* 0.08
10 (1 - 0.08)

11 = 0.007497

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.114873

Line		**Post - 1996 Total PTF**	-	**Post - 1996 PTF CWIP**	=	**Post -1996 PTF Excluding CWIP**	
13	INVESTMENT BASE	$ 515,437,566		$ -		$ 515,437,566	From Worksheet 1B, line 13, 14
14	x Cost of Capital Rate	0.1148730		0.1148730		0.1148730	
15	= Investment Return and Income Taxes	$ 59,209,860		$ -		$ 59,209,860	To Worksheet 1A, line 14

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Provided this support because the balance in "Total Inv. Base" will be revised under the Changed Rates

Western Massachusetts Electric Company (WMECO)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Present Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014

Investment Return and Income Taxes - Post-1996

Investment Return and Income Taxes - 50bp

Line	(A)	(B) CAPITALIZATION (B) (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 578,162,814	50.45%		0.00%		
2	PREFERRED STOCK		0.00%		0.00%	0.00%	
3	COMMON EQUITY	$ 578,162,814	50.45%	0.50%	0.25%	0.25%	
4	TOTAL INVESTMENT RETURN	$ 1,156,325,628	100.90%		0.25%	0.25%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.0025

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit (W/S 1B) + Eq. AFUDC of Deprec. Exp. (Att. I)) / PTF Inv. Base (W/S 1B) x Federal Income Tax Rate)
(1 - Federal Income Tax Rate)

6 = (0.0025 +(0 + 0) / 553,657,881) x 0.35)
7 (1 - 0.35)

8 = 0.001346

(c) State Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate
(1 - State Income Tax Rate)

9 = (0.0025 +(0 + 0) / 553,657,881) + 0.001346)* 0.08
10 (1 - 0.08)

11 = 0.000334

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.004180

Line		**Total PTF**	-
13	INVESTMENT BASE	$ 553,657,881	
14	x Cost of Capital Rate	0.0041800	
15	= Investment Return and Income Taxes	$ 2,314,290	

Notes:
(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-217, Schedule 1, Page 2 of 2
(2) Provided this support because the balance in "Total Inv. Base" will be revised under the Changed Rates

Western Massachusetts Electric Company (WMECO)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Present Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Worksheet 3C

LN.		(1) Transmission	(2) Wage/Plant Allocation Factors (a)	(3) Transmission	Pre-1997 PTF (4) PTF Allocation Factor (b)	Pre-1997 PTF (5) = (3)*(4) PTF Allocated	Post-1996 PTF (6) PTF Allocation Factor (b)	Post-1996 PTF (7) = (3)*(6) Post-96 PTF Allocated	Reference	Notes
	Transmission Plant									
1	Transmission Plant					53,145,202		717,553,491	Attachment A2	(1)
2	General Plant	18,793,854		18,793,854	6.1211%	1,150,391	82.6455%	15,532,275	FF1 page 204 ln. 99, footnote	(1)
3	Total (line 1+2)	18,793,854		18,793,854		54,295,593		733,085,766		(1)
										(1)
4	Transmission Plant Held for Future Use	0		0	6.1211%	0	82.6455%	0	FF1 page 214 ln. 13	(1)
	Transmission Accumulated Depreciation									
5	Transmission Accum. Depreciation	54,279,720		54,279,720	6.1211%	3,322,516	82.6455%	44,859,746	FF1 page 219 ln. 25	(1)
6	General Plant Accum. Depreciation	4,371,591		4,371,591	6.1211%	267,589	82.6455%	3,612,923	FF1 page 219 ln. 28, footnote	(1)
7	Total (line 5+6)	58,651,311		58,651,311		3,590,105		48,472,669		(1)
	Transmission Accumulated Deferred Taxes									
8	Accumulated Deferred Taxes (281-283)	(225,957,746)		(225,957,746)	6.1211%	(13,831,100)	82.6455%	(186,743,909)	FF1 page 274 ln. 9 & 276 ln. 19, footnotes	(1)
9	Accumulated Deferred Taxes (190)	5,663,481 (c)		5,663,481	6.1211%	346,667	82.6455%	4,680,612	(c)	(1)
10	Total (line 8+9)	(220,294,265)		(220,294,265)		(13,484,433)		(182,063,297)		(1)
11	Transmission loss on Reacquired Debt	331,119		331,119	6.1211%	20,268	82.6455%	273,655	FF1 page 110 ln. 81, footnote	(1)
	Other Regulatory Assets									
12	FAS 106	22,693		22,693	6.1211%	1,389	82.6455%	18,755	FF1 page 232.1 ln. 1, footnote	(1)
13	FAS 109	9,336,822		9,336,822	6.1211%	571,516	82.6455%	7,716,463	FF1 page 232 ln. 9, footnote	(1)
14	Other Regulatory Liabilities (254.DK)	(65,339)		(65,339)	6.1211%	(3,999)	82.6455%	(54,000)	FF1 page 278 ln. 5, footnote	(1)
15	Total (line 12+13+14)	9,294,176		9,294,176		568,906		7,681,218		(1)
16	Transmission Prepayments	1,023,867		1,023,867	6.1211%	62,672	82.6455%	846,180	FF1 page 110 ln. 57, footnote	(1)
17	Transmission Materials and Supplies	3,143,646		3,143,646	6.1211%	192,426	82.6455%	2,598,082	FF1 page 227 ln. 8	(1)
	Cash Working Capital									
18	Operation & Maintenance Expense					389,810		5,263,108	W/S 4C, Line 16	(1)
19	Administrative & General Expense					492,228		6,645,940	W/S 4C, Line 17	(2)
20	Transmission Support Expense					357,869			W/S 7	(1)
21	Subtotal (line 19+20+21)					1,239,907		11,909,048		(2)
22						0.125		0.125	x 45 / 360	(1)
23	Total (line 22 * line 23)					154,988		1,488,631		(2)

(a) All items are specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries and Plant Allocation Factors are not used (column 2).
(b) W/S 5A & 5B

(c)				
	Account 190	5,663,481	FF1 page 234 ln. 18, footnote	(1)
	Less Reserve for Disputed Transactions	-	FF1 page 234 ln. 18, footnote	(1)
	Total Account 190	5,663,481		(1)

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
Provided this support because these balances will be revised under the changed rates.

Western Massachusetts Electric Company (WMECO)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Present Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Worksheet 4C

					Pre-1997 PTF		Post-1996 PTF			
LN.		(1) Transmission	(2) Wage/Plant Allocation Factors (a)	(3) Transmission	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	(6) PTF Allocation Factor (b)	(7) = (3)*(6) Post-96 PTF Allocated	Reference	Notes
	Depreciation Expense									
1	Transmission Depreciation	15,972,687		15,972,687	6.1211%	977,704	82.6455%	13,200,707	FF1 page 336 ln. 7	(1)
2	General Depreciation	789,658		789,658	6.1211%	48,336	82.6455%	652,617	FF1 page 336 ln. 10, footnote	(1)
3	Total (line 1+2)	16,762,345		16,762,345		1,026,040		13,853,324		(1)
4	Amortization of Loss on Reacquired Debt	49,668		49,668	6.1211%	3,040	82.6455%	41,048	FF1 page 114, ln. 64, footnote	(1)
5	Amortization of Investment Tax Credits	35,604		35,604	6.1211%	2,179	82.6455%	29,425	FF1 page 266 ln. 8(f), footnote	(1)
	Property Taxes									
6	Transmission Property Taxes	18,717,332		18,717,332	6.1211%	1,145,707	82.6455%	15,469,033	FF1 page 262 ln. 32i, footnote	(1)
7	General Property Taxes (c)				6.1211%	-	82.6455%	-		(1)
8	Total (line 6+7)	18,717,332		18,717,332		1,145,707		15,469,033		(1)
	Transmission Operation and Maintenance									
9	Operation and Maintenance	20,725,279		20,725,279	6.1211%	1,268,615	82.6455%	17,128,510	FF1 page 321 ln. 112	(1)
10	Transmission of Electricity by Others - #565	13,174,678		13,174,678	6.1211%	806,435	82.6455%	10,888,279	FF1 page 321 ln. 96	(1)
11	Account 561.1	12,368		12,368	6.1211%	757	82.6455%	10,222	FF1 page 321 ln. 85	(1)
12	Account 561.2	50,569		50,569	6.1211%	3,095	82.6455%	41,793	FF1 page 321 ln. 86	(1)
13	Account 561.3	13,262		13,262	6.1211%	812	82.6455%	10,960	FF1 page 321 ln. 87	(1)
14	Account 561.4	1,106,108		1,106,108	6.1211%	67,706	82.6455%	914,148	FF1 page 321 ln. 88	(1)
15	**Station Expenses & Rents	-			6.1211%	-	82.6455%	-	FF1 page 321 ln. 93 + ln. 98	(1)
16	O&M less lines 10 thru 15	6,368,294		6,368,294		389,810		5,263,108		(1)
	Transmission Administrative and General									
17	Administrative and General	8,041,502		8,041,502	6.1211%	492,228	82.6455%	6,645,940	FF1 page 320 ln. 197, footnote	(2)
18	*Payroll Tax Expense*	18,291		18,291	6.1211%	1,120	82.6455%	15,117		(1)
	Federal Unemployment	283							FF1 page 262 ln. 3i, footnote	(1)
	FICA	13,202							FF1 page 262 ln. 5i, footnote	(1)
	Medicare	3,757							FF1 page 262 ln. 9i, footnote	(1)
	CT Unemployment	852							FF1 page 262 ln. 13i, footnote	(1)
	DC Unemployment	1							FF1 page 262.1 ln. 6i, footnote	(1)
	FL Unemployment	-							FF1 page 262.1 ln. 10i, footnote	(1)
	GA Unemployment	-							FF1 page 262.1 ln. 14i footnote	(1)
	MA Unemployment	69							FF1 page 262 ln. 22i, footnote	(1)
	MA Universal Health	19							FF1 page 262 ln. 27i, footnote	(1)
	MI Unemployment	-							FF1 page 262.1 ln. 14i footnote	(1)
	NH Unemployment	108							FF1 page 262 ln. 37i, footnote	(1)
	NJ Unemployment	-							FF1 page 262 footnote	(1)
	NY Unemployment	-							FF1 page 262.1, footnote	(1)
	Total	18,291	To Line 19							(1)

** To the extent that PTF Support Payments are reflected in worksheet 7 they will be excluded from this calculation.
(a) All items are specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries and Plant Allocation Factors are not used (column 2).
(b) W/S 5A & 5B
(c) Transmission related general property taxes are included in the Transmission Property tax number footnoted in the FF1.

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
Provided this support because these balances will be revised under the changed rates.

Exhibit No. ES-214
Schedule 3

CL&P's, PSNH's, and WMECO's PTF Revenue Requirements under the Changed Rates

Eversource Energy Service Company

CL&P, PSNH, and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For the Calendar Year 2016

Line	(A) Description	(B) Reference	(C) CL&P	(D) PSNH	(E) WMECO	(F)=(C)+(D)+(E) Total
1	2014 Actual PTF Revenue Requirements		$ 470,448,936 (1)	$ 111,748,555 (2)	$ 114,313,984 (3)	$ 696,511,475
2	Estimated 2015 PTF Plant Additions	(4)	$ 276,000,000	$ 114,000,000	$ 87,000,000	$ 477,000,000
3	Carrying Charge Factor (CCF)	Exhibit No. ES-214, Schedule 2, Page 3 of 20, Note (3)	15.25%	16.55%	14.00%	
4	2015 Incremental Estimated PTF Revenue Requirements	Line 2 x 3	42,090,000	18,867,000	12,180,000	$ 73,137,000
5	2015 Incremental Estimated PTF CWIP Rev. Req.	(4)	$ (19,400,000)	$ -	$ -	$ (19,400,000)
6	Total Estimated PTF Revenue Requirement for 2015	Line 1 + 4 + 5	$ 493,138,936	$ 130,615,555	$ 126,493,984	$ 750,248,475
7	Estimated 2016 PTF Plant Additions	(4)	$ 68,000,000	$ 117,000,000	$ 88,000,000	$ 273,000,000
8	Carrying Charge Factor (CCF)	Line 3	15.25%	16.55%	14.00%	
9	2016 Incremental Estimated PTF Revenue Requirements	Line 7 x 8	10,370,000	19,363,500	12,320,000	$ 42,053,500
10	Total Estimated PTF Revenue Requirement for 2016	Line 6 + 9	$ 503,508,936	$ 149,979,055	$ 138,813,984	$ 792,301,975

Notes:
(1) Exhibit No. ES-214: Schedule 3, Page 2 of 20, LN. 29(B) + Schedule 3, Page 3 of 20, LN. 29(B) + Schedule 3, Page 4 of 20, LN. 5(B) + Schedule 3, Page 5 of 20, LN. 9(B)
(2) Exhibit No. ES-214: Schedule 3, Page 2 of 20, LN. 29(C) + Schedule 3, Page 3 of 20, LN. 29(C) + Schedule 3, Page 4 of 20, LN. 5(C)
(3) Exhibit No. ES-214: Schedule 3, Page 2 of 20, LN. 29(D) + Schedule 3, Page 3 of 20, LN. 29(D) + Schedule 3, Page 4 of 20, LN. 5(D) + Schedule 3, Page 5 of 20, LN. 9(C)
(4) Based on Eversource's Forecast

CL&P, PSNH, and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Pre-1997

		(A)		(B)	(C)	(D)	(E)=(B)+(C)+(D)	(F)	(G)
LN.	I.	INVESTMENT BASE	Attachment F Reference Section:	CL&P	PSNH	WMECO	Total	Reference	Notes
1		Transmission Plant	(A)(1)(a)	358,812,326	88,564,672	53,145,202	500,522,200	W/S 3A,3B,3C line 1	(1)
2		General Plant	(A)(1)(b)	12,027,048	7,336,167	1,150,391	20,513,606	W/S 3A,3B,3C line 2	(1)
3		Plant Held For Future Use	(A)(1)(c)	84,157	1,138,376	0	1,222,533	W/S 3A,3B,3C line 4	(1)
4		Total Plant (Lines 1+2+3)		370,923,531	97,039,215	54,295,593	522,258,339		(1)
5		Accumulated Depreciation	(A)(1)(d)	73,042,167	17,223,185	3,590,105	93,855,457	W/S 3A,3B,3C line 7	(1)
6		Accumulated Deferred Income Taxes	(A)(1)(e)	49,105,827	16,884,906	13,484,433	79,475,166	W/S 3A,3B,3C line 10	(1)
7		Loss On Reacquired Debt	(A)(1)(f)	623,759	245,415	20,268	889,442	W/S 3A,3B,3C line 11	(1)
8		Other Regulatory Assets	(A)(1)(g)	2,278,427	1,052,873	568,906	3,900,206	W/S 3A,3B,3C line 15	(1)
9		Net Investment (Line 4-5-6+7+8)		251,677,723	64,229,412	37,810,229	353,717,364		(1)
10		Prepayments	(A)(1)(h)	1,885,610	662,602	62,672	2,610,884	W/S 3A,3B,3C line 16	(1)
11		Materials & Supplies	(A)(1)(i)	4,547,780	1,261,158	192,426	6,001,364	W/S 3A,3B,3C line 17	(1)
12		Cash Working Capital	(A)(1)(j)	1,340,088	444,915	191,379	1,976,382	W/S 3A,3B,3C line 23	(2)
13		Total Investment Base (Line 9+10+11+12)		259,451,201	66,598,087	38,256,706	364,305,994		(2)
	II.	REVENUE REQUIREMENTS							
14		Investment Return and Income Taxes	(A)	32,256,530	7,933,764	4,394,663	44,584,957	W/S 2A,2B,2C	(2)
15		Depreciation Expense	(B)	8,594,771	1,919,255	1,026,040	11,540,066	W/S 4A,4B,4C line 3	(1)
16		Amortization of Loss on Reacquired Debt	(C)	68,393	30,531	3,040	101,964	W/S 4A,4B,4C line 4	(1)
17		Investment Tax Credit	(D)	(49,341)	(600)	(2,179)	(52,120)	W/S 4A,4B,4C line 5	(1)
18		Property Tax Expense	(E)	5,226,750	2,236,785	1,145,707	8,609,242	W/S 4A,4B,4C line 8	(1)
19		Payroll Tax Expense	(F)	37,155	(505)	1,120	37,770	W/S 4A,4B,4C line 18	(1)
20		Operation & Maintenance Expense	(G)	4,360,357	1,271,570	389,810	6,021,737	W/S 4A,4B,4C line 16	(1)
21		Administrative & General Expense	(H)	6,360,349	1,783,479	783,351	8,927,179	W/S 4A,4B,4C line 19	(2)
22		Transmission Related Integrated Facilities Charge	(I)	-	-	-	-	N/A	(1)
23		Transmission Support Revenue	(J)	(2,917,925)	(376,198)	-	(3,294,123)	W/S 7	(1)
24		Transmission Support Expense	(K)	1,625,568	880,469	357,869	2,863,906	W/S 7	(1)
25		Transmission Related Expense from Generators	(L)	-	-	-	-	N/A	(1)
26		Transmission Related Taxes and Fees Charge	(M)	1,135,268	19,553	1,263	1,156,084	Attachment B, line 14	(1)
27		Revenue for ST Trans. Service Under the OATT	(N)	(68,394)	(16,040)	(8,880)	(93,314)	Attachment C, line 9	(1)
28		Transmission Rents Received from Electric Property	(O)	(5,239,993)	(1,821,957)	(402,030)	(7,463,980)	Attachment C1, line 3	(1)
29		Total Revenue Requirements (Line 14 thru 28)		51,389,488	13,860,106	7,689,774	72,939,368		(2)

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

CL&P, PSNH, and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Post-1996
Worksheet 1B

LN.		(A)	Attachment F Reference Section:	(B) CL&P	(C) PSNH	(D) WMECO	(E)=(B)+(C)+(D) Total	(F) Reference	(G) Notes
	I.	INVESTMENT BASE							
1		Transmission Plant	(A)(1)(a)	2,415,403,244	568,289,707	717,553,491	3,701,246,442	W/S 3A,3B,3C line 1	(1)
2		General Plant	(A)(1)(b)	80,962,316	47,073,591	15,532,275	143,568,182	W/S 3A,3B,3C line 2	(1)
3		Plant Held For Future Use	(A)(1)(c)	566,521	7,304,557	-	7,871,078	W/S 3A,3B,3C line 4	(1)
4		Total Plant (Lines 1+2+3)		2,496,932,081	622,667,855	733,085,766	3,852,685,702		(1)
5		Accumulated Depreciation	(A)(1)(d)	491,696,956	110,515,089	48,472,669	650,684,714	W/S 3A,3B,3C line 7	(1)
6		Accumulated Deferred Income Taxes	(A)(1)(e)	330,565,024	108,344,471	182,063,297	620,972,792	W/S 3A,3B,3C line 10	(1)
7		Loss On Reacquired Debt	(A)(1)(f)	4,198,950	1,574,739	273,655	6,047,344	W/S 3A,3B,3C line 11	(1)
8		Other Regulatory Assets	(A)(1)(g)	15,337,661	6,755,912	7,681,218	29,774,791	W/S 3A,3B,3C line 15	(1)
9		Net Investment (Line 4-5-6+7+8)		1,694,206,712	412,138,946	510,504,673	2,616,850,331		(1)
10		Prepayments	(A)(1)(h)	12,693,335	4,251,680	846,180	17,791,195	W/S 3A,3B,3C line 16	(1)
11		Materials & Supplies	(A)(1)(i)	30,614,229	8,092,403	2,598,082	41,304,714	W/S 3A,3B,3C line 17	(1)
12		Cash Working Capital	(A)(1)(j)	9,021,054	2,450,396	1,979,965	13,451,415	W/S 3A,3B,3C line 23	(2)
13		Total Investment Base Excluding CWIP (Line 9+10+11+12)		1,746,535,330	426,933,425	515,928,900	2,689,397,655		(2)
14		NEEWS Construction Work In Progress	(A)(1)(l)	164,948,530		-	164,948,530	(a)	(1)
15		Total Investment Base Including CWIP (Line 13+14)		1,911,483,860	426,933,425	515,928,900	2,854,346,185		(2)
	II.	REVENUE REQUIREMENTS							
16		Investment Return and Income Taxes	(A)	217,052,425	50,860,152	59,266,301	327,178,878	W/S 2A,2B,2C	(2)
17		Investment Return and Income Taxes-CWIP		20,499,144	-	-	20,499,144	W/S 2A,2B,2C	(1)
18		Depreciation Expense	(B)	57,857,303	12,315,183	13,853,324	84,025,810	W/S 4A,4B,4C line 3	(1)
19		Amortization of Loss on Reacquired Debt	(C)	460,401	195,905	41,048	697,354	W/S 4A,4B,4C line 4	(1)
20		Investment Tax Credit	(D)	(332,148)	(3,850)	(29,425)	(365,423)	W/S 4A,4B,4C line 5	(1)
21		Property Tax Expense	(E)	35,184,843	14,352,660	15,469,033	65,006,536	W/S 4A,4B,4C line 8	(1)
22		Payroll Tax Expense	(F)	250,119	(3,240)	15,117	261,996	W/S 4A,4B,4C line 18	(1)
23		Operation & Maintenance Expense	(G)	29,352,552	8,159,213	5,263,108	42,774,873	W/S 4A,4B,4C line 16	(1)
24		Administrative & General Expense	(H)	42,815,877	11,443,955	10,576,612	64,836,444	W/S 4A,4B,4C line 19	(2)
25		Transmission Related Integrated Facilities Charge	(I)	-	-	-	-	N/A	(1)
26		Transmission Related Expense from Generators	(L)	-	-	-	-	N/A	(1)
27		Transmission Related Taxes and Fees Charge	(M)	7,642,269	125,466	17,047	7,784,782	Attachment B line 16	(1)
28		Revenue for ST Trans. Service Under the OATT	(N)	(460,565)	(102,948)	(119,820)	(683,333)	Attachment C line 10	(1)
29		Total Revenue Requirements (Line 16 thru 28)		410,322,220	97,342,496	104,352,345	612,017,061		(2)

(a) Reflects actual information per Eversource's accounting records

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

CL&P, PSNH, and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Post-2003
Worksheet 1C

	(A)	(B)	(C)	(D)	(E)=(B)+(C)+(D)	(F)	(G)
LN.	I. INVESTMENT BASE	CL&P	PSNH	WMECO	TOTAL	REFERENCE	Notes
1	Transmission Plant	$ 1,535,579,816	$ 124,215,608	$ 12,384,353	$ 1,672,179,777	Attachment D, D2, D4	(1)
2	Accumulated Depreciation	$ 213,218,089	$ 18,074,549	$ 1,442,093	$ 232,734,731	Attachment D, D2, D4	(1)
3	Accumulated Deferred Income Taxes	$ 155,340,565	$ 15,930,789	$ 2,675,475	$ 173,946,829	Attachment D1, D3, D5	(1)
4	Net Investment (Line 1-2-3)	$ 1,167,021,162	$ 90,210,270	$ 8,266,785	$ 1,265,498,217		(1)
	II. INCREMENTAL RETURN						
5	Incremental Revenue Requirements	$ 6,906,431	$ 545,953	$ 47,005	$ 7,499,389	W/S 2A,2B,2C Post 2003	(1)

Note: ROE incentives approved in FERC Opinion No. 489. As a result of Opinion No. 531-B, these projects receive an ROE incentive of 67 bp.

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.

CL&P, PSNH, and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
NEEWS
Worksheet 1E

LN.	(A) I. INVESTMENT BASE	(B) CL&P	(C) WMECO	(D) = (B) + (C) Total	(E) REFERENCE	(F) Notes
1	Transmission Plant	$ 200,288,632	$ 556,313,751	$ 756,602,383	Attachment F & F2	(1)
2	Accumulated Depreciation	$ 8,946,318	$ 22,283,705	$ 31,230,023	Attachment F & F2	(1)
3	Accumulated Deferred Income Taxes	$ 46,929,968	$ 142,742,742	$ 189,672,710	Attachment F1 & F3	(1)
4	Net Investment Excluding CWIP(Line 1-2-3)	$ 144,412,346	$ 391,287,304	$ 535,699,650		(1)
5	NEEWS Construction Work In Progress	$ 164,948,530	$ -	$ 164,948,530	Attachment F & F2	(1)
6	Net Investment Including CWIP(Line 4+5)	$ 309,360,876	$ 391,287,304	$ 700,648,180		(1)
	II. INCREMENTAL RETURN					
7	Incremental Revenue Requirements	$ 854,632	$ 2,224,860	$ 3,079,492	W/S 2A & 2C NEEWS	(1)
8	Incremental Revenue Requirements-CWIP	$ 976,165	$ -	$ 976,165	W/S 2A & 2C NEEWS	(1)
9	Total Incremental Revenue Requirements (line 7+8)	$ 1,830,797	$ 2,224,860	$ 4,055,657		(1)

Note: Incentives approved in FERC Docket No. ER08-1548. As a result of Opinion No. 531-B, this project receives ROE incentives of 67 bp.

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.

Connecticut Light & Power Company (CL&P)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Investment Return and Income Taxes - Pre 1997
Worksheet 2A

Line	(A)		(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$	2,579,060,322	45.78%	5.36%	2.45%		
2	PREFERRED STOCK	$	116,868,097	2.07%	4.80%	0.10%	0.10%	
3	COMMON EQUITY	$	2,938,441,767	52.15%	11.07%	5.77%	5.77%	
4	TOTAL INVESTMENT RETURN	$	5,634,370,186	100.00%		8.32%	5.87%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.0832

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit (W/S 1A) + Eq. AFUDC of Deprec. Exp. (Att. I)) / PTF Inv. Base (W/S 1A) x Federal Income Tax Rate)
(1 - Federal Income Tax Rate)

6 = 0.0587 +((49,341) + 269,748) / 259,451,201) x 0.35)
7 (1 - 0.35)

8 = 0.032065

(c) State Income Tax = R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate
(1 - State Income tax Rate)

9 = 0.0587 +((49,341) + 269,748) / 259,451,201) + 0.032065)* 0.09
10 (1 - 0.09)

11 = 0.009061

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.124326

Line			**Pre-1997 PTF**	
13	INVESTMENT BASE	$	259,451,201	From Worksheet 1A, line 13
14	x Cost of Capital Rate		0.124326	
15	= Investment Return and Income Taxes	$	32,256,530	To Worksheet 1A, line 14

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Connecticut Light & Power Company (CL&P)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Investment Return and Income Taxes - Post 1996
Worksheet 2A

Line	(A)	(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 2,579,060,322	45.78%	5.36%	2.45%		
2	PREFERRED STOCK	$ 116,868,097	2.07%	4.80%	0.10%	0.10%	
3	COMMON EQUITY	$ 2,938,441,767	52.15%	11.07%	5.77%	5.77%	
4	TOTAL INVESTMENT RETURN	$ 5,634,370,186	100.00%		8.32%	5.87%	

Cost of Capital Rate=

Line										
5	(a) Weighted Cost of Capital	=	0.0832							
	(b) Federal Income Tax	= (	R.O.E. +	(	PTF Inv. (Tax Credit (W/S 1B)	+	Eq. AFUDC of Deprec. Exp. (Att. I)	) /	PTF Inv. Base (W/S 1B)	x Federal Income Tax Rate)
							(1 - Federal Income Tax Rate)			
6		=	0.0587	+(	(332,148)	+	1,815,862	) /	1,911,483,860)	x 0.35)
7							(1	-	0.35)	
8		=	0.032026							
	(c) State Income Tax	=	R.O.E. +	(	PTF Inv. (Tax Credit	+	Eq. AFUDC of Deprec. Exp.	) /	PTF Inv. Base)	+ Federal Income Tax)*State Income Tax Rate
							(1 - State Income tax Rate)			
9		=	0.0587	+(	(332,148)	+	1,815,862	) /	1,911,483,860)	+ 0.032026)* 0.09
10							(1	-	0.09)	
11		=	0.009050							
12	(a)+(b)+(c) Cost of Capital Rate	=	0.124276							

Line		**Post - 1996 Total PTF**	-	**Post - 1996 PTF CWIP**	=	**Post -1996 PTF Excluding CWIP**	
13	INVESTMENT BASE	$ 1,911,483,860		$ 164,948,530		$ 1,746,535,330	From Worksheet 1B, line 13, 14
14	x Cost of Capital Rate	0.124276		0.124276		0.124276	
15	= Investment Return and Income Taxes	$ 237,551,568		$ 20,499,144		$ 217,052,425	To Worksheet 1B, line 16

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Connecticut Light & Power Company (CL&P)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Investment Return and Income Taxes - 50bp

Line	(A)	(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 2,579,060,322	45.78%		0.00%		
2	PREFERRED STOCK	$ 116,868,097	2.07%		0.00%	0.00%	
3	COMMON EQUITY	$ 2,938,441,767	52.15%	0.50%	0.26%	0.26%	
4	TOTAL INVESTMENT RETURN	$ 5,634,370,186	100.00%		0.26%	0.26%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.0026

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit (W/S 1B) + Eq. AFUDC of Deprec. Exp. (Att. I)) / PTF Inv. Base (W/S 1B) x Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

6 = 0.0026 +(0 + 0) / 2,170,935,061) x 0.35)
7 (1 - 0.35)

8 = 0.001400

(c) State Income Tax = R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate / (1 - State Income tax Rate)

9 = 0.0026 +(0 + 0) / 2,170,935,061) + 0.001400)* 0.09
10 (1 - 0.09)

11 = 0.000396

12 (a)+(b)+(c) Cost of Capital Rate = 0.004396

Line		Total PTF
13	INVESTMENT BASE	$ 2,170,935,061
14	x Cost of Capital Rate	0.004396
15	= Investment Return and Income Taxes	$ 9,543,431

Notes:
(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-217, Schedule 1, Page 2 of 2
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Connecticut Light & Power Company (CL&P)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Worksheet 3A

					Pre-1997 PTF		Post-1996 PTF			
		(1)	(2)	(3)	(4)	(5) = (3)*(4)	(6)	(7) = (3)*(6)		
			Wage/Plant		PTF		PTF			
			Allocation		Allocation	PTF	Allocation	PTF		
LN.		Transmission	Factors (a)	Transmission	Factor (b)	Allocated	Factor (b)	Allocated	Reference	Notes
	Transmission Plant									
1	Transmission Plant					358,812,326		2,415,403,244	Attachment A (H1)	(1)
2	General Plant	104,400,554		104,400,554	11.5201%	12,027,048	77.5497%	80,962,316	FF1 page 204 ln. 99, footnote	(1)
3	Total (line 1+2)	104,400,554		104,400,554		370,839,374		2,496,365,560		(1)
										(1)
4	Transmission Plant Held for Future Use	730,526 (c)		730,526	11.5201%	84,157	77.5497%	566,521	(c)	(1)
	Transmission Accumulated Depreciation									
5	Transmission Accum. Depreciation	605,238,764		605,238,764	11.5201%	69,724,111	77.5497%	469,360,846	FF1 page 219 ln. 25	(1)
6	General Plant Accum. Depreciation	28,802,317		28,802,317	11.5201%	3,318,056	77.5497%	22,336,110	FF1 page 219 ln. 28, footnote	(1)
7	Total (line 5+6)	634,041,081		634,041,081		73,042,167		491,696,956	Schedule 2, Page 6,7,8	(1)
	Transmission Accumulated Deferred Taxes									
8	Accumulated Deferred Taxes (281 to 283)	(470,775,688)		(470,775,688)	11.5201%	(54,233,830)	77.5497%	(365,085,134)	FF1 page 274 ln. 9 & 276 ln. 19 fns	(1)
9	Accumulated Deferred Taxes (190)	44,513,531 (d)		44,513,531	11.5201%	5,128,003	77.5497%	34,520,110	(d)	(1)
10	Total (line 8+9)	(426,262,157)		(426,262,157)		(49,105,827)		(330,565,024)		(1)
11	Transmission loss on Reacquired Debt	5,414,528		5,414,528	11.5201%	623,759	77.5497%	4,198,950	FF1 page 110 ln. 81, footnote	(1)
	Other Regulatory Assets									
12	FAS 106	66,791		66,791	11.5201%	7,694	77.5497%	51,796	FF1 page 232 Ln. 27, footnote	(1)
13	FAS 109	23,019,567		23,019,567	11.5201%	2,651,877	77.5497%	17,851,605	FF1 page 232 ln. 7, footnote	(1)
14	Other Regulatory Liabilities (254.DK)	(3,308,510)		(3,308,510)	11.5201%	(381,144)	77.5497%	(2,565,740)	FF1 page 278 ln. 3, footnote	(1)
15	Total (line 12+13+14)	19,777,848		19,777,848		2,278,427		15,337,661		(1)
16	Transmission Prepayments (165)	16,368,000		16,368,000	11.5201%	1,885,610	77.5497%	12,693,335	FF1 page 110 ln. 57, footnote	(1)
17	Transmission Materials and Supplies	39,476,915		39,476,915	11.5201%	4,547,780	77.5497%	30,614,229	FF1 page 227 ln. 8	(1)
	Cash Working Capital									
18	Operation & Maintenance Expense					4,360,357		29,352,552	W/S 4A, Line 16	(1)
19	Administrative & General Expense					6,360,349		42,815,877	W/S 4A, Line 19	(2)
20	Transmission Support Expense					-		-	W/S 7	(1)
21	Subtotal (line 18+19+20)					10,720,706		72,168,429		(2)
22						0.125		0.125	x 45 / 360	(1)
23	Total (line 21 * line 22)					1,340,088		9,021,054		(2)

(a) All items are specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries and Plant Allocation Factors are not used (column
(b) W/S 5A & 5B

(c)	Account 105	32,127,498	FF1 page 214 ln. 33	(1)
	Less Third Underground Conduit Duct	31,396,972	FF1 page 214 ln. 22	(1)
		730,526		(1)
(d)	Account 190	46,955,376	FF1 page 234 ln. 18, footnote	(1)
	Less Reserve for Disputed Transactions	2,441,845	FF1 page 234 ln. 18, footnote	(1)
	Total Account 190	44,513,531		(1)

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Connecticut Light & Power Company (CL&P)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Worksheet 4A

LN.		(1) Transmission	(2) Wage/Plant Allocation Factors (a)	(3) Transmission	PRE-97 PTF (4) PTF Allocation Factor (b)	PRE-97 PTF (5) = (3)*(4) PTF Allocated	POST-96 PTF (6) PTF Allocation Factor (b)	POST-96 PTF (7) = (3)*(6) Post-96 PTF Allocated	Reference	Notes
	Depreciation Expense									
1	Transmission Depreciation	69,626,166		69,626,166	11.5201%	8,021,004	77.5497%	53,994,883	FF1 page 336 ln. 7	(1)
2	General Depreciation	4,980,574		4,980,574	11.5201%	573,767	77.5497%	3,862,420	FF1 page 336 ln. 10, footnote	(1)
3	Total (line 1+2)	74,606,740		74,606,740		8,594,771		57,857,303		(1)
4	Amortization of Loss on Reacquired Debt	593,685		593,685	11.5201%	68,393	77.5497%	460,401	FF1 page 114 ln. 64, footnote	(1)
5	Amortization of Investment Tax Credits	428,304		428,304	11.5201%	49,341	77.5497%	332,148	FF1 page 266 ln. 8(f), footnote	(1)
	Property Taxes									
6	Transmission Property Taxes	45,370,701		45,370,701	11.5201%	5,226,750	77.5497%	35,184,843	FF1 page 262 ln. 25i, footnote	(1)
7	General Property Taxes (c)	-		-	11.5201%	-	77.5497%	-		(1)
8	Total (line 6+7)	45,370,701		45,370,701		5,226,750		35,184,843		(1)
	Transmission Operation and Maintenance									
9	Operation and Maintenance	77,432,007		77,432,007	11.5201%	8,920,245	77.5497%	60,048,289	FF1 page 321 ln. 112	(1)
10	Transmission of Electricity by Others - #565	21,727,966		21,727,966	11.5201%	2,503,083	77.5497%	16,849,972	FF1 page 321 ln. 96	(1)
11	Account 561.1	3,245,594		3,245,594	11.5201%	373,896	77.5497%	2,516,948	FF1 page 321 ln. 85	(1)
12	Account 561.2	5,212,556		5,212,556	11.5201%	600,492	77.5497%	4,042,322	FF1 page 321 ln. 86	(1)
13	Account 561.3	2,238,612		2,238,612	11.5201%	257,890	77.5497%	1,736,037	FF1 page 321 ln. 87	(1)
14	Account 561.4	7,157,291		7,157,291	11.5201%	824,527	77.5497%	5,550,458	FF1 page 321 ln. 88	(1)
15	**Station Expenses & Rents	-		-	11.5201%	-	77.5497%	-	FF1 page 321 ln. 93 + ln. 98	(1)
16	O&M less lines 10 thru 15	37,849,988		37,849,988		4,360,357		29,352,552		(1)
	Transmission Administrative and General									
17	Administrative and General	37,202,294		37,202,294	11.5201%	4,285,741	77.5497%	28,850,267	FF1 page 320 ln. 197 b, footnote	(1)
18	Transmission Merger-Related Costs	18,008,593		18,008,593	11.5201%	2,074,608	77.5497%	13,965,610	**Exhibit No. ES-201, Page 1 of 1, Line 23(H)**	(2)
19	Total (line 17 + 18)					6,360,349		42,815,877		(2)
20	*Payroll Tax Expense*	322,527		322,527	11.5201%	37,155	77.5497%	250,119		(1)
	Federal Unemployment	5,226							FF1 page 262 ln. 3i, footnote	(1)
	FICA	233,351							FF1 page 262 ln. 5i, footnote	(1)
	Medicare	65,613							FF1 page 262 ln. 9i, footnote	(1)
	CT Unemployment	16,786							FF1 page 262 ln. 15i, footnote	(1)
	DC Unemployment	11							FF1 page 262.1 ln. 14i, footnote	(1)
	FL Unemployment	1							FF1 page 262.1 ln. 18i, footnote	(1)
	GA Unemployment	-							FF1 page 262 footnote	(1)
	MA Unemployment	(285)							FF1 page 262 ln. 32i, footnote	(1)
	MA Universal Health	64							FF1 page 262 ln. 33i, footnote	(1)
	MI Unemployment	6							FF1 page 262.1 ln. 22i, footnote	(1)
	NH Unemployment	1,754							FF1 page 262.1 ln. 4i, footnote	(1)
	NJ Unemployment	-							FF1 page 262 footnote	(1)
	NY Unemployment	-							FF1 page 262.1 ln. 10i, footnote	(1)
	Total	322,527	To Line 18							(1)

** To the extent that PTF Support Payments are reflected in worksheet 7 they will be excluded from this calculation.
(a) All items are specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries and Plant Allocation Factors are not used (column 2).
(b) W/S 5A & 5B
(c) Transmission related general property taxes are included in the Transmission Property tax number footnoted in the FF1.

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Public Service Company of New Hampshire (PSNH)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Investment Return and Income Taxes - Pre 1997
Worksheet 2B

Line	(A)	(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 1,070,020,120	46.56%	4.15%	1.93%		
2	PREFERRED STOCK	$ -	0.00%	0.00%	0.00%	0.00%	
3	COMMON EQUITY	$ 1,228,095,985	53.44%	11.07%	5.92%	5.92%	
4	TOTAL INVESTMENT RETURN	$ 2,298,116,105	100.00%		7.85%	5.92%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.0785

(b) Federal Income Tax =((R.O.E. + (PTF Inv. (Tax Credit (W/S 1A) + Eq. AFUDC of Deprec. Exp. (Att. I)) / PTF Inv. Base (W/S 1A) x Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

6 =(0.0592 +((600) + 29,005) / 66,598,087) x 0.35)
7 (1 - 0.35)

8 = 0.032107

(c) State Income Tax =(R.O.E. + +(PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate / (1 - State Income Tax Rate)

9 =(0.0592 +((600) + 29,005) / 66,598,087) + 0.032107)* 0.085
10 (1 - 0.085)

11 = 0.008522

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.119129

Line		**Pre-1997 PTF**	
13	INVESTMENT BASE	$ 66,598,087	From Worksheet 1A, line 13
14	x Cost of Capital Rate	0.1191290	
15	= Investment Return and Income Taxes	$ 7,933,764	To Worksheet 1A, line 14

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Public Service Company of New Hampshire (PSNH)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Investment Return and Income Taxes - Pre 1997
Worksheet 2B

Line	(A)	(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 1,070,020,120	46.56%	4.15%	1.93%		
2	PREFERRED STOCK	$ -	0.00%	0.00%	0.00%	0.00%	
3	COMMON EQUITY	$ 1,228,095,985	53.44%	11.07%	5.92%	5.92%	
4	TOTAL INVESTMENT RETURN	$ 2,298,116,105	100.00%		7.85%	5.92%	

Cost of Capital Rate=

Line									
5	(a) Weighted Cost of Capital	=	0.0785						
	(b) Federal Income Tax	= (	(R.O.E. +	(PTF Inv. (Tax Credit (W/S 1B) +	Eq. AFUDC of Deprec. Exp. (Att. I)) /	PTF Inv. Base (W/S 1A)	x	Federal Income Tax Rate)	
					(1 - Federal Income Tax Rate)				
6		= (	0.0592	+((3,850) +	186,109) /	426,933,425)	x	0.35)	
7					(1 -	0.35)			
8		=	0.032107						
	(c) State Income Tax	= (	R.O.E. +	+(PTF Inv. (Tax Credit +	Eq. AFUDC of Deprec. Exp.) /	PTF Inv. Base)	+	Federal Income Tax)*State Income Tax Rate	
					(1 - State Income Tax Rate)				
9		= (	0.0592	+((3,850) +	186,109) /	426,933,425)	+	0.032107)*	0.085
10					(1 -	0.085)			
11		=	0.008522						
12	(a)+(b)+(c) Cost of Capital Rate	=	0.119129						

Line		**Post - 1996Total PTF**	
13	INVESTMENT BASE	$ 426,933,425	From Worksheet 1A, line 13
14	x Cost of Capital Rate	0.119129	
15	= Investment Return and Income Taxes	$ 50,860,152	To Worksheet 1B, line 16

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Public Service Company of New Hampshire (PSNH)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Investment Return and Income Taxes - 50bp

Line	(A)	(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 1,070,020,120	46.56%		0.00%		
2	PREFERRED STOCK	$ -	0.00%		0.00%	0.00%	
3	COMMON EQUITY	$ 1,228,095,985	53.44%	0.50%	0.27%	0.27%	
4	TOTAL INVESTMENT RETURN	$ 2,298,116,105	100.00%		0.27%	0.27%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.0027

(b) Federal Income Tax = ((R.O.E. + (PTF Inv. (Tax Credit (W/S 1B) + Eq. AFUDC of Deprec. Exp. (Att. I)) / PTF Inv. Base (W/S 1A) x Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

6 = (0.0027 +(0 + 0) / 493,531,512) x 0.35)
7 (1 - 0.35)

8 = 0.001454

(c) State Income Tax = (R.O.E. + +(PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate / (1 - State Income Tax Rate)

9 = (0.0027 +(0 + 0) / 493,531,512) + 0.001454)* 0.085
10 (1 - 0.085)

11 = 0.000386

12 (a)+(b)+(c) Cost of Capital Rate = 0.004540

Line		Total PTF
13	INVESTMENT BASE	$ 493,531,512
14	x Cost of Capital Rate	0.004540
15	= Investment Return and Income Taxes	$ 2,240,633

Notes:

(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-217, Schedule 1, Page 2 of 2
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Public Service Company of New Hampshire (PSNH)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Worksheet 3B

					Pre-1997 PTF		Post-1996 PTF			
		(1)	(2)	(3)	(4)	(5) = (3)*(4)	(6)	(7) = (3)*(6)		
LN.		Transmission	Wage/Plant Allocation Factors (a)	Transmission	PTF Allocation Factor (b)	PTF Allocated	PTF Allocation Factor (b)	Post-96 PTF Allocated	Reference	Notes
	Transmission Plant									
1	Transmission Plant					88,564,672		568,289,707	Attachment A1	(1)
2	General Plant	59,322,426		59,322,426	12.3666%	7,336,167	79.3521%	47,073,591	FF1 page 204 ln. 99, footnote	(1)
3	Total (line 1+2)	59,322,426		59,322,426		95,900,839		615,363,298		(1)
										(1)
4	Transmission Plant Held for Future Use	9,205,247		9,205,247	12.3666%	1,138,376	79.3521%	7,304,557	FF1 page 214 ln. 35	(1)
	Transmission Accumulated Depreciation									
5	Transmission Accum. Depreciation	123,132,357		123,132,357	12.3666%	15,227,286	79.3521%	97,708,111	FF1 page 219 ln. 25	(1)
6	General Plant Accum. Depreciation	16,139,432		16,139,432	12.3666%	1,995,899	79.3521%	12,806,978	FF1 page 219 ln. 28, footnote	(1)
7	Total (line 5+6)	139,271,789		139,271,789		17,223,185		110,515,089		(1)
	Transmission Accumulated Deferred Taxes									
8	Accumulated Deferred Taxes (281-283)	(145,475,861)		(145,475,861)	12.3666%	(17,990,418)	79.3521%	(115,438,151)	FF1 page 274 ln. 9 & 276 ln. 19 fns	(1)
9	Accumulated Deferred Taxes (190)	8,939,499 (c)		8,939,499	12.3666%	1,105,512	79.3521%	7,093,680	(c)	(1)
10	Total (line 8+9)	(136,536,362)		(136,536,362)		(16,884,906)				
				-						
11	Transmission loss on Reacquired Debt	1,984,496		1,984,496	12.3666%	245,415	79.3521%	1,574,739	FF1 page 110 ln. 81, footnote	(1)
	Other Regulatory Assets									
12	FAS 106	350,591		350,591	12.3666%	43,356	79.3521%	278,201	FF1 page 232.1 ln. 15, footnote	(1)
13	FAS 109	8,171,016		8,171,016	12.3666%	1,010,477	79.3521%	6,483,873	FF1 page 232 ln. 1, footnote	(1)
14	Other Regulatory Liabilities (254.DK)	(7,765)		(7,765)	12.3666%	(960)	79.3521%	(6,162)	FF1 page 278 ln. 1, footnote	(1)
15	Total (line 12+13+14)	8,513,842		8,513,842		1,052,873		6,755,912		(1)
16	Transmission Prepayments	5,357,993		5,357,993	12.3666%	662,602	79.3521%	4,251,680	FF1 page 110 ln. 57, footnote	(1)
17	Transmission Materials and Supplies	10,198,096		10,198,096	12.3666%	1,261,158	79.3521%	8,092,403	FF1 page 227 ln. 8	(1)
	Cash Working Capital									
18	Operation & Maintenance Expense					1,271,570		8,159,213	W/S 4B, Line 16	(1)
19	Administrative & General Expense					1,783,479		11,443,955	W/S 4B, Line 19	(2)
20	Transmission Support Expense					504,271		-	W/S 7	(1)
21	Subtotal (line 18+19+20)					3,559,320		19,603,168		(2)
22						0.125		0.125	x 45 / 360	(1)
23	Total (line 21 * line 22)					444,915		2,450,396		(2)

(a) All items are specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries and Plant Allocation Factors are not used (column 2).
(b) W/S 5A & 5B
(c)

Account 190	8,939,499	FF1 page 234 ln. 18, footnote	(1)
Less Reserve for Disputed Transactions	-	FF1 page 234 ln. 18, footnote	(1)
Total Account 190	8,939,499		(1)

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Public Service Company of New Hampshire (PSNH)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Worksheet 4B

LN.		(1) Transmission	(2) Wage/Plant Allocation Factors (a)	(3) Transmission	Pre-1997 PTF (4) PTF Allocation Factor (b)	Pre-1997 PTF (5) = (3)*(4) PTF Allocated	Post-1996 PTF (6) PTF Allocation Factor (b)	Post-1996 PTF (7) = (3)*(6) Post-96 PTF Allocated	Reference	Notes
	Depreciation Expense									
1	Transmission Depreciation	12,792,512		12,792,512	12.3666%	1,581,999	79.3521%	10,151,127	FF 1 page 336 ln. 7	(1)
2	General Depreciation	2,727,156		2,727,156	12.3666%	337,256	79.3521%	2,164,056	FF1 page 336 ln. 10, footnote	(1)
3	Total (line 1+2)	15,519,668		15,519,668		1,919,255		12,315,183		(1)
4	Amortization of Loss on Reacquired Debt	246,881		246,881	12.3666%	30,531	79.3521%	195,905	FF1 page 114 ln. 64, footnote	(1)
5	Amortization of Investment Tax Credits	4,852		4,852	12.3666%	600	79.3521%	3,850	FF1 page 266 ln. 8(f), footnote	(1)
	Property Taxes									
6	Transmission Property Taxes	18,087,310		18,087,310	12.3666%	2,236,785	79.3521%	14,352,660	FF1 page 262 ln. 23i + ln. 30i +	(1)
7	General Property Taxes (c)	-		-	12.3666%	-	79.3521%	-	page 262.1 ln. 2i, footnote	(1)
8	Total (line 6+7)	18,087,310		18,087,310		2,236,785		14,352,660		(1)
	Transmission Operation and Maintenance									
9	Operation and Maintenance	51,082,852		51,082,852	12.3666%	6,317,212	79.3521%	40,535,316	FF1 page 321 ln. 112	(1)
10	Transmission of Electricity by Others - #565	37,174,569		37,174,569	12.3666%	4,597,230	79.3521%	29,498,801	FF1 page 321 ln. 96	(1)
11	Account 561.1	653,575		653,575	12.3666%	80,825	79.3521%	518,625	FF1 page 321 ln. 85	(1)
12	Account 561.2	474,690		474,690	12.3666%	58,703	79.3521%	376,676	FF1 page 321 ln. 86	(1)
13	Account 561.3	36,962		36,962	12.3666%	4,571	79.3521%	29,330	FF1 page 321 ln. 87	(1)
14	Account 561.4	2,460,768		2,460,768	12.3666%	304,313	79.3521%	1,952,671	FF1 page 321 ln. 88	(1)
15	**Station Expenses & Rents	-		-	12.3666%	-	79.3521%	-	FF1 page 321 ln. 93 + ln. 98	(1)
16	O&M less lines 10 thru 15	10,282,288		10,282,288		1,271,570		8,159,213		(1)
	Transmission Administrative and General									
17	Administrative and General	10,348,117		10,348,117	12.3666%	1,279,710	79.3521%	8,211,448	FF1 page 320 ln. 197 b, footnote	(1)
18	Transmission Merger-Related Costs	4,073,625		4,073,625	12.3666%	503,769	79.3521%	3,232,507	**Exhibit No. ES-201, Page 1 of 1, Line 25(H)**	(2)
19	Total (line 17 + 18)					1,783,479		11,443,955		(2)
20	*Payroll Tax Expense*	(4,083)		(4,083)	12.3666%	(505)	79.3521%	(3,240)		(1)
	Federal Unemployment	(51)							FF1 page 262 ln. 2i, footnote	(1)
	FICA	(3,062)							FF1 page 262 ln. 4i, footnote	(1)
	Medicare	(816)							FF1 page 262 ln. 7i, footnote	(1)
	CT Unemployment	(128)							FF1 page 262.1 ln. 7i, footnote	(1)
	DC Unemployment	0							FF1 page 262 ln. 26i, footnote	(1)
	FL Unemployment	0							FF1 page 262.1 ln. 27i, footnote	(1)
	GA Unemployment	0							FF1 page 262.1, footnote	(1)
	MA Unemployment	2							FF1 page 262.1 ln. 15i, footnote	(1)
	MA Universal Health	(1)							FF1 page 262.1 ln. 16i, footnote	(1)
	MI Unemployment	0							FF1 page 262.1 ln. 31i, footnote	(1)
	NH Unemployment	(27)							FF1 page 262 ln. 14i, footnote	(1)
	NJ Unemployment	0							FF1 page 262, footnote	(1)
	NY Unemployment	0							FF1 page 262 footnote	(1)
	Total	(4,083)	To Line 19							(1)

** To the extent that PTF Support Payments are reflected in worksheet 7 they will be excluded from this calculation.
(a) All items are specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries and Plant Allocation Factors are not used (column 2).
(b) W/S 5A & 5B
(c) Transmission related general property taxes are included in the Transmission Property tax number footnoted in the FF1.

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-00
(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expense

Western Massachusetts Electric Company (WMECO)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Investment Return and Income Taxes - Pre 1997
Worksheet 2C

Line	(A)	(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 567,833,428	49.55%	4.31%	2.14%		
2	PREFERRED STOCK	$ -	0.00%	0.00%	0.00%	0.00%	
3	COMMON EQUITY	$ 578,162,814	50.45%	11.07%	5.58%	5.58%	
4	TOTAL INVESTMENT RETURN	$ 1,145,996,242	100.00%		7.72%	5.58%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.0772

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit (W/S 1A) + Eq. AFUDC of Deprec. Exp. (Att. I)) / PTF Inv. Base (W/S 1A) x Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

6 = (0.0558 +((2,179) + 11,396) / 38,256,706) x 0.35)
7 (1 - 0.35)

8 = 0.030176

(c) State Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate / (1 - State Income Tax Rate)

9 = (0.0558 +((2,179) + 11,396) / 38,256,706) + 0.030176)* 0.08
10 (1 - 0.08)

11 = 0.007497

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.114873

Line		**Pre-1997 PTF**	
13	INVESTMENT BASE	$ 38,256,706	From Worksheet 1A, line 13
14	x Cost of Capital Rate	0.114873	
15	= Investment Return and Income Taxes	$ 4,394,663	To Worksheet 1A, line 14

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Western Massachusetts Electric Company (WMECO)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014

Investment Return and Income Taxes - Post-1997

Worksheet 2C

Line	(A)	(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 567,833,428	49.55%	4.31%	2.14%		
2	PREFERRED STOCK	$ -	0.00%	0.00%	0.00%	0.00%	
3	COMMON EQUITY	$ 578,162,814	50.45%	11.07%	5.58%	5.58%	
4	TOTAL INVESTMENT RETURN	$ 1,145,996,242	100.00%		7.72%	5.58%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.0772

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit (W/S 1B) + Eq. AFUDC of Deprec. Exp. (Att. I)) / PTF Inv. Base (W/S 1B) x Federal Income Tax Rate)
(1 - Federal Income Tax Rate)

6 = (0.0558 +((29,425) + 153,859) / 515,928,900) x 0.35)
7 (1 - 0.35)

8 = 0.030176

(c) State Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate
(1 - State Income Tax Rate)

9 = (0.0558 +((29,425) + 153,859) / 515,928,900) + 0.030176)* 0.08
10 (1 - 0.08)

11 = 0.007497

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.114873

Line		**Post - 1996 Total PTF**	-	**Post - 1996 PTF CWIP**	=	**Post -1996 PTF Excluding CWIP**	
13	INVESTMENT BASE	$ 515,928,900		$ -		$ 515,928,900	From Worksheet 1B, line 13, 14
14	x Cost of Capital Rate	0.1148730		0.1148730		0.1148730	
15	= Investment Return and Income Taxes	$ 59,266,301		$ -		$ 59,266,301	To Worksheet 1A, line 14

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Western Massachusetts Electric Company (WMECO)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014

Investment Return and Income Taxes - Post-1997

Line	(A)	(B) CAPITALIZATION (B) (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 578,162,814	50.45%		0.00%		
2	PREFERRED STOCK		0.00%		0.00%	0.00%	
3	COMMON EQUITY	$ 578,162,814	50.45%	0.50%	0.25%	0.25%	
4	TOTAL INVESTMENT RETURN	$ 1,156,325,628	100.90%		0.25%	0.25%	

Cost of Capital Rate=

Line											
5	(a) Weighted Cost of Capital	=	0.0025								
	(b) Federal Income Tax	=	(R.O.E. +	(PTF Inv. (Tax Credit (W/S 1B) +	Eq. AFUDC of Deprec. Exp. (Att. I)	) /	PTF Inv. Base (W/S 1B)	x Federal Income Tax Rate)			
					(1 - Federal Income Tax Rate)						
6		=	(0.0025	+(0 +	0	) /	554,185,606	) x	0.35)		
7				(	1	-	0.35)				
8		=	0.001346								
	(c) State Income Tax	=	(R.O.E. +	(PTF Inv. (Tax Credit +	Eq. AFUDC of Deprec. Exp.	) /	PTF Inv. Base)	+ Federal Income Tax)*State Income Tax Rate			
					(1 - State Income Tax Rate)						
9		=	(0.0025	+(0 +	0	) /	554,185,606	) +	0.001346	)*	0.08
10				(	1	-	0.08)				
11		=	0.000334								
12	(a)+(b)+(c) **Cost of Capital Rate**	=	0.004180								

Line		**Total PTF**	-
13	INVESTMENT BASE	$ 554,185,606	
14	x Cost of Capital Rate	0.0041800	
15	= Investment Return and Income Taxes	$ 2,316,496	

Notes:

(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-217, Schedule 1, Page 2 of 2
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Western Massachusetts Electric Company (WMECO)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Worksheet 3C

					Pre-1997 PTF		Post-1996 PTF			
		(1)	(2)	(3)	(4)	(5) = (3)*(4)	(6)	(7) = (3)*(6)		
			Wage/Plant		PTF		PTF	Post-96		
			Allocation		Allocation	PTF	Allocation	PTF		
LN.		Transmission	Factors (a)	Transmission	Factor (b)	Allocated	Factor (b)	Allocated	Reference	Notes
	Transmission Plant									
1	Transmission Plant					53,145,202		717,553,491	Attachment A2	(1)
2	General Plant	18,793,854		18,793,854	6.1211%	1,150,391	82.6455%	15,532,275	FF1 page 204 ln. 99, footnote	(1)
3	Total (line 1+2)	18,793,854		18,793,854		54,295,593		733,085,766		(1)
										(1)
4	Transmission Plant Held for Future Use	0		0	6.1211%	0	82.6455%	0	FF1 page 214 ln. 13	(1)
	Transmission Accumulated Depreciation									
5	Transmission Accum. Depreciation	54,279,720		54,279,720	6.1211%	3,322,516	82.6455%	44,859,746	FF1 page 219 ln. 25	(1)
6	General Plant Accum. Depreciation	4,371,591		4,371,591	6.1211%	267,589	82.6455%	3,612,923	FF1 page 219 ln. 28, footnote	(1)
7	Total (line 5+6)	58,651,311		58,651,311		3,590,105		48,472,669		(1)
	Transmission Accumulated Deferred Taxes									
8	Accumulated Deferred Taxes (281-283)	(225,957,746)		(225,957,746)	6.1211%	(13,831,100)	82.6455%	(186,743,909)	FF1 page 274 ln. 9 & 276 ln. 19, footnotes	(1)
9	Accumulated Deferred Taxes (190)	5,663,481 (c)		5,663,481	6.1211%	346,667	82.6455%	4,680,612	(c)	(1)
10	Total (line 8+9)	(220,294,265)		(220,294,265)		(13,484,433)		(182,063,297)		(1)
11	Transmission loss on Reacquired Debt	331,119		331,119	6.1211%	20,268	82.6455%	273,655	FF1 page 110 ln. 81, footnote	(1)
	Other Regulatory Assets									
12	FAS 106	22,693		22,693	6.1211%	1,389	82.6455%	18,755	FF1 page 232.1 ln. 1, footnote	(1)
13	FAS 109	9,336,822		9,336,822	6.1211%	571,516	82.6455%	7,716,463	FF1 page 232 ln. 9, footnote	(1)
14	Other Regulatory Liabilities (254.DK)	(65,339)		(65,339)	6.1211%	(3,999)	82.6455%	(54,000)	FF1 page 278 ln. 5, footnote	(1)
15	Total (line 12+13+14)	9,294,176		9,294,176		568,906		7,681,218		(1)
16	Transmission Prepayments	1,023,867		1,023,867	6.1211%	62,672	82.6455%	846,180	FF1 page 110 ln. 57, footnote	(1)
17	Transmission Materials and Supplies	3,143,646		3,143,646	6.1211%	192,426	82.6455%	2,598,082	FF1 page 227 ln. 8	(1)
	Cash Working Capital									
18	Operation & Maintenance Expense					389,810		5,263,108	W/S 4C, Line 16	(1)
19	Administrative & General Expense					783,351		10,576,612	W/S 4C, Line 19	(2)
20	Transmission Support Expense					357,869			W/S 7	(1)
21	Subtotal (line 19+20+21)					1,531,030		15,839,720		(2)
22						0.125		0.125	x 45 / 360	(1)
23	Total (line 22 * line 23)					191,379		1,979,965		(2)

(a) All items are specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries and Plant Allocation Factors are not used (column 2).
(b) W/S 5A & 5B

(c)				
	Account 190	5,663,481	FF1 page 234 ln. 18, footnote	(1)
	Less Reserve for Disputed Transactions	-	FF1 page 234 ln. 18, footnote	(1)
	Total Account 190	5,663,481		(1)

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses
-

Western Massachusetts Electric Company (WMECO)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Worksheet 4C

					Pre-1997 PTF		Post-1996 PTF			
		(1)	(2) Wage/Plant Allocation	(3)	(4) PTF Allocation	(5) = (3)*(4) PTF	(6) PTF Allocation	(7) = (3)*(6) Post-96 PTF		
LN.		Transmission	Factors (a)	Transmission	Factor (b)	Allocated	Factor (b)	Allocated	Reference	Notes
	Depreciation Expense									
1	Transmission Depreciation	15,972,687		15,972,687	6.1211%	977,704	82.6455%	13,200,707	FF1 page 336 ln. 7	(1)
2	General Depreciation	789,658		789,658	6.1211%	48,336	82.6455%	652,617	FF1 page 336 ln. 10, footnote	(1)
3	Total (line 1+2)	16,762,345		16,762,345		1,026,040		13,853,324		(1)
4	Amortization of Loss on Reacquired Debt	49,668		49,668	6.1211%	3,040	82.6455%	41,048	FF1 page 114, ln. 64, footnote	(1)
5	Amortization of Investment Tax Credits	35,604		35,604	6.1211%	2,179	82.6455%	29,425	FF1 page 266 ln. 8(f), footnote	(1)
	Property Taxes									
6	Transmission Property Taxes	18,717,332		18,717,332	6.1211%	1,145,707	82.6455%	15,469,033	FF1 page 262 ln. 32i, footnote	(1)
7	General Property Taxes (c)				6.1211%	-	82.6455%	-		(1)
8	Total (line 6+7)	18,717,332		18,717,332		1,145,707		15,469,033		(1)
	Transmission Operation and Maintenance									
9	Operation and Maintenance	20,725,279		20,725,279	6.1211%	1,268,615	82.6455%	17,128,510	FF1 page 321 ln. 112	(1)
10	Transmission of Electricity by Others - #565	13,174,678		13,174,678	6.1211%	806,435	82.6455%	10,888,279	FF1 page 321 ln. 96	(1)
11	Account 561.1	12,368		12,368	6.1211%	757	82.6455%	10,222	FF1 page 321 ln. 85	(1)
12	Account 561.2	50,569		50,569	6.1211%	3,095	82.6455%	41,793	FF1 page 321 ln. 86	(1)
13	Account 561.3	13,262		13,262	6.1211%	812	82.6455%	10,960	FF1 page 321 ln. 87	(1)
14	Account 561.4	1,106,108		1,106,108	6.1211%	67,706	82.6455%	914,148	FF1 page 321 ln. 88	(1)
15	**Station Expenses & Rents	-			6.1211%	-	82.6455%	-	FF1 page 321 ln. 93 + ln. 98	(1)
16	O&M less lines 10 thru 15	6,368,294		6,368,294		389,810		5,263,108		(1)
	Transmission Administrative and General									
17	Administrative and General	8,041,502		8,041,502	6.1211%	492,228	82.6455%	6,645,940	FF1 page 320 ln. 197, footnote	(1)
18	Transmission Merger-Related Costs	4,756,064		4,756,064	6.1211%	291,123	82.6455%	3,930,673	**Exhibit No. ES-201, Page 1 of 1, Line 26(H)**	(2)
19	Total (line 17 + 18)					783,351		10,576,612		(2)
20	*Payroll Tax Expense*	18,291		18,291	6.1211%	1,120	82.6455%	15,117		(1)
	Federal Unemployment	283							FF1 page 262 ln. 3i, footnote	(1)
	FICA	13,202							FF1 page 262 ln. 5i, footnote	(1)
	Medicare	3,757							FF1 page 262 ln. 9i, footnote	(1)
	CT Unemployment	852							FF1 page 262 ln. 13i, footnote	(1)
	DC Unemployment	1							FF1 page 262.1 ln. 6i, footnote	(1)
	FL Unemployment	-							FF1 page 262.1 ln. 10i, footnote	(1)
	GA Unemployment	-							FF1 page 262.1 ln. 14i footnote	(1)
	MA Unemployment	69							FF1 page 262 ln. 22i, footnote	(1)
	MA Universal Health	19							FF1 page 262 ln. 27i, footnote	(1)
	MI Unemployment	-							FF1 page 262.1 ln. 14i footnote	(1)
	NH Unemployment	108							FF1 page 262 ln. 37i, footnote	(1)
	NJ Unemployment	-							FF1 page 262 footnote	(1)
	NY Unemployment	-							FF1 page 262.1, footnote	(1)
	Total	18,291	To Line 19							(1)

** To the extent that PTF Support Payments are reflected in worksheet 7 they will be excluded from this calculation.
(a) All items are specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries and Plant Allocation Factors are not used (column 2).
(b) W/S 5A & 5B
(c) Transmission related general property taxes are included in the Transmission Property tax number footnoted in the FF1.

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Exhibit No. ES-215
Schedule 1

Summary of Impact on NSTAR Electric's PTF Revenue Requirements under Attachment F of ISO-NE OATT (1-year amortization)

Eversource Energy Service Company

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirement Comparison Under Present and Changed Rates
Under Attachment F of the ISO-NE OATT
For the Calendar year 2016

	(A)	(B)		(C)		(D) = (C) - (B)		(E) = (D) / (B)
Line	Description	Total PTF Revenue Requirements		Total PTF Revenue Requirements Including Merger-Related Costs		Difference		% Difference
1	2016 Estimated NSTAR Electric PTF Revenue Requirements	$ 262,066,250	(1)	$ 270,876,119	(2)	$ 8,810,000	(3)	3.4%

Notes:

(1) Exhibit No. ES-215, Schedule 2, Page 1 of 5, Line 10(C)

(2) Exhibit No. ES-215, Schedule 3, Page 1 of 5, Line 10(C)

(3) In connection with the one-year amortization proposal (with the proposed effective date of June 1, 2016), Eversource is showing the revenue impact for the twelve-month period June 1, 2016 through May 31, 2017. Eversource is using revenue requirement calculations for the calendar year 2016 as an estimate for the twelve-month period beginning June 1, 2016. See Cooper Testimony Exhibit No. ES-200.

	2016	2017	Total
The amounts for each year are as follows:	$ 5,139,167	$ 3,670,833	$ 8,810,000

Exhibit No. ES-215
Schedule 2

NSTAR Electric’s PTF Revenue Requirements under the Present Rates

Eversource Energy Service Company

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements
Calculated under the Present Rates in Attachment F of the ISO-NE OATT
For the Calendar Year 2016

	(A)	(B)	(C)	
Line	**Description**	**Reference**	**NSTAR Electric**	
1	2014 Actual PTF Revenue Requirements	Exhibit No. ES-215, Schedule 2, Page 2 of 5, Line 30, Col.D	$	216,579,241
2	Estimated 2015 PTF Plant Additions	(1)	$	146,000,000
3	Carrying Charge Factor (CCF)	Exhibit No. ES-215, Schedule 2, Page 2 of 5, Note (3)		13.89%
4	2015 Incremental Estimated PTF Revenue Requirements	Line 2 x 3	$	20,279,943
5	2015 Incremental Estimated PTF Intangible Plant Rev. Req.	(1)	$	343,300
6	Total Estimated PTF Revenue Requirement for 2015	Line 1 + 4 + 5	$	237,202,484
7	Estimated 2016 PTF Plant Additions	(1)	$	179,000,000
8	Carrying Charge Factor (CCF)	Line 3		13.89%
9	2016 Incremental Estimated PTF Revenue Requirements	Line 7 x 8	$	24,863,766
10	Total Estimated PTF Revenue Requirement for 2016	Line 6 + 9	$	262,066,250

Notes:
(1) Based on Eversource's Forecast

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements
Calculated under the Present Rates in Attachment F of the ISO-NE OATT
For Costs in 2014
Sheet 2a

Line	Investment Base	Attachment F Reference Section:	Pre-1997	Post-1996	Reference	Notes
	Col.A	Col.B	Col.C	Col.D	Col.E	
1	Transmission Plant	II (A)(1)(a)	$ 394,245,298	$ 1,176,211,529	Sheet 4, line 1	(1)
2	General Plant	II (A)(1)(b)	4,064,182	12,125,263	Sheet 4, line 2	(1)
3	Plant Held For Future Use	II (A)(1)(c)	-	13,571,504	Sheet 4, line 4	(1)
4	**Total Plant** (Line 1 + 2 + 3)		398,309,480	1,201,908,296		
5	Accumulated Depreciation	II (A)(1)(d)	(95,102,434)	(283,732,865)	Sheet 4, line 7	(1)
6	Accumulated Deferred Income Taxes	II (A)(1)(e)	(75,011,955)	(223,794,030)	Sheet 4, line 11	(1)
7	Loss On Reacquired Debt	II (A)(1)(f)	757,488	2,259,924	Sheet 4, line 12	(1)
8	Other Regulatory Assets	II (A)(1)(g)	4,930,985	14,711,323	Sheet 4, line 16	(1)
9	**Net Investment** (Line 4 + 5 + 6 + 7 + 8)		233,883,564	711,352,648		
10	Prepayments	II (A)(1)(h)	2,283,784	6,813,544	Sheet 4, line 17	(1)
11	Materials & Supplies	II (A)(1)(II)	5,909,946	17,631,999	Sheet 4, line 18	(1)
12	Cash Working Capital	II (A)(1)(j)	1,019,059	2,974,825	Sheet 4, line 24	(2)
13	**Total Investment Base** (Line 9 + 10 + 11 + 12)		$ 243,096,353	$ 738,773,016		(2)
	Revenue Requirement					
14	Investment Return and Income Taxes	II (A)	$ 30,191,595	$ 93,229,112	Sheet 3a, Line 26	(2)
15	Depreciation Expense	II (B)	8,679,581	25,895,050	Sheet 5, Line 3	(1)
16	Amortization of Loss on Reacquired Debt	II (C)	58,839	175,544	Sheet 5, Line 4	(1)
17	Investment Tax Credit	II (D)	(77,133)	(230,121)	Sheet 5, Line 5	(1)
18	Property Taxes	II (E)	7,099,692	21,181,538	Sheet 5, Line 6	(1)
19	Payroll tax Expense	II (F)	269,960	805,411	Sheet 5, Line 22	(1)
20	Operation & Maintenance Expense	II (G)	4,580,096	13,664,461	Sheet 5, Line 11	(1)
21	Administrative & General Expense	II (H)	3,396,791	10,134,142	Sheet 5, Line 20	(2)
22	Transmission Related Integrated Facilities Charge	II (I)	-	-	N/A	(1)
23	Transmission Support Revenue	II (J)	(1,153,965)	-	Sheet 7, Line 9	(1)
24	Transmission Support Expense	II (K)	1,329,554	-	Sheet 7, Line 9	(1)
25	Transmission Related Expense from Generators	II (L)	-	-	N/A	(1)
26	Transmission Related Taxes and Fees Charge	II (M)	104,168	310,778	Sheet 5, Line 21	(1)
27	Revenue for ST Trans Service Under NEPOOL Tariff	II (N)	(35,083)	(104,467)	Attachment B, Lines 9 & 10	(1)
28	Transmission Rents Received for Electric Property	II (O)	(2,926,302)	-	Attachment C, Line 3	(1)
29	**Total Revenue Requirements** (Sum of Lines 14 through 28)		$ 51,517,793	$ 165,061,448		(2)
30	**Total Pre-1997 and Post 1996** (Line 29 [Pre-1997 + Post-1996])			$ 216,579,241		(2)

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000. Provided this support because these balances will be revised under the changed rates.

(3) Carrying Charge Factor ((Sheet 3a, Line 17 (C) + Sheet 2a, Line 15 thru 21) / Line 1) **13.89%**

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements
Calculated under the Present Rates in Attachment F of the ISO-NE OATT
For Costs in 2014
Sheet 3a

Line	Description	Capitalization 12/31/14	Weighted Capitalization	Weighted Cost of Capital (a)	Weighted Cost of Capital	Equity Portion		Notes
	Col.A	Col.B	Col.C	Col.D	Col.E	Col.F		(1)
1	Long-Term Debt	$ 1,792,712,148	41.74%	4.19%	1.75%		FF1 112.24(c)	(1)
2	Preferred Stock	43,000,000	1.00%	4.56%	0.05%	0.05%	FF1 112.3(c)	(1)
3	Common Equity	2,459,452,736	57.26%	11.07%	6.34%	6.34%	FF1 112.16(c) less Line 3(c)	(1)
4	Total Investment Return	$ 4,295,164,884	100.00%		8.14%	6.39%	Sum of Lines 1 to 3	(1)
								(1)

ROE per ISO New England Inc. Transmission, Markets and Services Tariff, Section II Attachment F II.A.2.(iii), page 231 http://www.iso-ne.com/regulatory/tariff/sect_2/oatt/sect_ii.pdf (1)

Line	Description	Pre-97	Post-96		Notes
5	**Federal Income Tax (FIT)**	**Pre-97**	**Post-96**		(1)
6	A= Preferred & Equity Return	6.39%	6.39%	Line 4, Col F	(1)
7	B= Transmission Related Amortization of ITC	$ (77,133)	$ (230,121)	Sheet 2a, Line 17	(1)
8	C= Equity AFUDC Component of Depreciation Expense	$ 18,983	$ 56,635	Sheet 10, Column (g)	(1)
9	D= Transmission Investment Base	$ 243,096,353	$ 738,773,016	Sheet 2a, Line 13	(2)
10	FT = Federal Income Tax Rate	35.00%	35.00%	Federal Income Tax Rate	(1)
11	FIT = (A+[C+B)/D])(FT)/(1-FT)	3.42790%	3.42810%	Federal Income Tax	(1)
12	ST = State Income Tax Rate	8.00%	8.00%	State Tax Rate	(1)
13	**State Income Tax (SIT)**				(1)
14	SIT = (A+[(C+B)/D]+Federal Income Tax)(ST)/(1-ST)	0.8517%	0.8517%	State Income Tax	(1)
15	Allowed Return	12.4196%	12.4198%	line 4, Col.E + Line 11 + Line 14	(1)
16	D= Transmission Investment Base	$ 243,096,353	$ 738,773,016	Sheet 2a, Line 13	(2)
17	**Return**	$ 30,191,595	$ 91,754,131	Line 15 * Line 16	(2)
18	Incremental return for Post 2003 PTF Investment				
19	A= Incremental Return		0.6700%	Per Opinion No. 489 and Opinion No. 531-B (b)	(1)
20	Effective Incremental (a')		0.3800%	line 19 * line 3, Col C	(1)
21	Additional FIT (a'/A')		0.2046%	Incremental FIT = (A' x FT)/(1-FT)	(1)
22	Additional SIT (a'/A')		0.0508%	Incremental SIT = (A' + FIT)(ST)/(1-ST)	(1)
23	Additional Return		0.6354%	Sum lines 20 thru 22	(1)
24	Post 2003 PTF net Investment		$ 232,134,198	Sheet 8, line 15	(1)
25	Additional 100 bp Return Post 2003 PTF Investment		$ 1,474,981	Line 23 * Line 24	(1)
26	Total Return	$ 30,191,595	$ 93,229,112	Line 17 + Line 25	(2)

Line	Description	Capitalization 12/31/14	Weighted Capitalization	Weighted Cost of Capital	Weighted Cost of Capital	Equity Portion	Notes
27	**Incremental return for PTF 50 Basis Point Adder**						
28	Long-Term Debt	$ 1,792,712,148	41.74%	4.19%	1.75%		(1)
29	Preferred Stock	43,000,000	1.00%	4.56%	0.05%		(1)
30	Common Equity	2,459,452,736	57.26%	0.50%	0.29%	0.29%	(1)
31	Total Investment Return	$ 4,295,164,884	100.00%		2.09%	0.29%	(1)

Line	Description	Pre-97	Post-96		Notes
32	**Federal Income Tax (FIT)**	**Pre-97**	**Post-96**		
33	A= Incremental Return	0.29%	0.29%	Line 31, Col F	(1)
34	B= Transmission Related Amortization of ITC	$ -	$ -	N/A	(1)
35	C= Equity AFUDC Component of Depreciation Expense	$ -	$ -	N/A	(1)
36	D= Transmission Investment Base	$ 243,096,353	$ 738,773,016	Sheet 2a, Line 13	(2)
37	FT = Federal Income Tax Rate	35.00%	35.00%	Federal Income Tax Rate	(1)
38	FIT = (A+[C+B)/D])(FT)/(1-FT)	0.15620%	0.15620%	Federal Income Tax	(1)
39	ST = State Income Tax Rate	8.00%	8.00%	State Tax Rate	(1)
40	**State Income Tax (SIT)**				(1)
41	SIT = (A+[(C+B)/D]+Federal Income Tax)(ST)/(1-ST)	0.0388%	0.0388%	State Income Tax	(1)
					(1)
42	Allowed Return	0.4850%	0.4850%	line 33 + Line 38 + Line 41	(1)
43	D= Transmission Investment Base	$ 243,096,353	$ 738,773,016	Sheet 2a, Line 13	(2)
44	Return 50 bp Adder	$ 1,179,017	$ 3,583,049	Line 42 * Line 43	(2)
45	Total Return 50 bp Adder		$ 4,762,066	Line 44 Pre-97 + Line 44 Post 96	(2)
46	Total Incremental Return		$ 6,237,047	Line 25 + Line 45	(2)

(a) See Attachment F for weighted cost of debt and preferred stock support.
(b) As a result of Opinion No. 531-B, these projects receive an ROE incentive of 67 bp.

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
Provided this support because these balances will be revised under the changed rates.

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements
Calculated under the Present Rates in Attachment F of the ISO-NE OATT
For Costs in 2014
Sheet 4

Line	Description	Total	Wage/Plant Allocation Factors	Transmission Allocated	Pre-97 PTF Allocation Factor (a)	Pre-97 PTF Allocated	Post-96 PTF Allocation Factor (a)	Post-96 PTF Allocated	Reference	Notes
	Col.A	Col.B	Col.C	Col.D (Col.B x Col.C)	Col.E	Col.F (Col.D x Col.E)	Col.G	Col.H (Col.D x Col.G)	Col.I	(1) (1)
	Transmission Plant									(1)
1	Transmission Plant (exc SCADA)	$ 1,903,972,438		$ 1,903,972,438		$ 394,245,298		$ 1,176,211,529	Sheet 6, Line 1 (PTF) & Line 2 (Total)	(1)
2	General Plant	$ 186,941,660	10.4993% (b)	$ 19,627,566	20.7065%	$ 4,064,182	61.7767%	$ 12,125,263	FF1 207.99(g)	(1)
3	Total Transmission Plant (line 1 + 2)			$ 1,923,600,004		$ 398,309,480		$ 1,188,336,792		(1)
										(1)
4	Transmission Plant Held for Future Use	$ 13,571,504	100.0000%	$ 13,571,504	0.0000%	$ -	100.0000%	$ 13,571,504	FF1 214.14(d) to 18(d)	(1)
										(1)
	Transmission Accumulated Depreciation									(1)
5	Transmission Accum. Depreciation	$ (453,776,651)	100.0000%	$ (453,776,651)	20.7065%	$ (93,961,262)	61.7767%	$ (280,328,240)	FF1 219.25(b)	(1)
6	General Plant Accum.Depreciation	$ (52,490,917)	10.4993% (b)	$ (5,511,179)	20.7065%	$ (1,141,172)	61.7767%	$ (3,404,625)	FF1 219.28(b)	(1)
7	Total Transmission Acc Dep (line 5 + 6)			$ (459,287,830)		$ (95,102,434)		$ (283,732,865)		(1)
										(1)
	Transmission Accumulated Deferred Taxes									(1)
8	Accumulated Deferred Taxes (282) (d)	$ (1,143,462,163)	28.4332% (c)	$ (325,122,884)	20.7065%	$ (67,321,570)	61.7767%	$ (200,850,189)	FF1 275.9(k) - 275.4(k)	(1)
9	Accumulated Deferred Taxes (283)			$ (45,243,071)	20.7065%	$ (9,368,256)	61.7767%	$ (27,949,676)	Sheet 9, Line 25, Col D	(1)
10	Accumulated Deferred Taxes (190)			$ 8,103,112	20.7065%	$ 1,677,871	61.7767%	$ 5,005,835	Sheet 9, Line 10, Col D	(1)
11	Total ADIT (line 8 + 9 + 10)			$ (362,262,843)		$ (75,011,955)		$ (223,794,030)		(1)
										(1)
12	Transmission loss on Reacquired Debt	$ 12,865,994	28.4332% (c)	$ 3,658,214	20.7065%	$ 757,488	61.7767%	$ 2,259,924	FF1 111.81(c)	(1)
										(1)
	Other Regulatory Assets									(1)
13	FAS 106	$ -	10.4993% (b)	$ -					FF1 232	(1)
14	ASC 740 Regulatory Asset (FAS 109)	$ 87,768,732	28.4332% (c)	$ 24,955,459					FF1 232.29(f)	(1)
15	ASC 740 Regulatory Liability (FAS 109)	$ (4,015,556)	28.4332% (c)	$ (1,141,751)					FF1 278.2(f)	(1)
16	Total (line 13 + 14 + 15)	$ 83,753,176		$ 23,813,708	20.7065%	$ 4,930,985	61.7767%	$ 14,711,323		(1)
										(1)
17	Transmission Prepayments	$ 105,048,059	10.4993% (b)	$ 11,029,311	20.7065%	$ 2,283,784	61.7767%	$ 6,813,544	FF1 111.57(c)	(1)
										(1)
18	Transmission Materials and Supplies	$ 28,541,503	100.0000%	$ 28,541,503	20.7065%	$ 5,909,946	61.7767%	$ 17,631,999	FF1 227.8(c) + 227.5(c) Footnote	(1)
	Cash Working Capital									
19	Operation & Maintenance Expense					$ 4,580,096		$ 13,664,461	Sheet 5, line 11	(1)
20	Administrative & General Expense					$ 3,396,791		$ 10,134,142	Sheet 5, line 20	(2)
21	Net Transmission Support Expense					$ 175,589		$ -	Sheet 7, line 9	(1)
22	Total (line 19 + 20 + 21)					$ 8,152,476		$ 23,798,603		(2)
23	45 day allowance per tariff					0.1250		0.1250	= 45 days / 360 days	(1)
24	Cash Working Capital (line 22 * 23)					$ 1,019,059		$ 2,974,825		(2)

(a) PTF Allocator (Sheet 6, Line 3)
(b) Wages & Salaries Allocator (Sheet 6, Line 13)
(c) Plant Allocator (Sheet 6, Line 18)
(d) ADIT in FERC Account 282 excludes ADIT associated with transition property from FF1 275.4(k)

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000. Provided this support because these balances will be revised under the changed rates.

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements
Calculated under the Present Rates in Attachment F of the ISO-NE OATT
For Costs in 2014
Sheet 5

Line	Description	Total	Wage/Plant Allocation Factors	Transmission Allocated	Pre-97 PTF Allocation Factor (a)	Pre-97 PTF Allocated	Post-96 PTF Allocation Factor (a)	Post-96 PTF Allocated	Reference	Notes
	Col.A	Col.B	Col.C	Col.D (Col.B x Col.C)	Col.E	Col.F (Col.D x Col.E)	Col.G	Col.H (Col.D x Col.G)	Col.I	
	Depreciation Expense									
1	Transmission Depreciation	$ 41,001,613		$ 41,001,613	20.7065%	$ 8,489,999	61.7767%	$ 25,329,443	FF1 336.7(b)	(1)
2	General Depreciation	$ 8,720,270	10.4993% (b)	$ 915,567	20.7065%	$ 189,582	61.7767%	$ 565,607	FF1 336.10(b)	(1)
3	Total (line 1 + 2)	$ 49,721,883		$ 41,917,180		$ 8,679,581		$ 25,895,050		(1)
										(1)
4	Amortization of Loss on Reacquired Debt	$ 999,391	28.4332% (c)	$ 284,159	20.7065%	$ 58,839	61.7767%	$ 175,544	FF1 117.64(c)	(1)
										(1)
5	Amortization of Investment Tax Credits	$ 1,310,106	28.4332% (c)	$ 372,505	20.7065%	$ 77,133	61.7767%	$ 230,121	FF1 114.19(c)	(1)
										(1)
	Property Taxes									(1)
6	Transmission Property Taxes	$ 120,588,821	28.4332% (c)	$ 34,287,261	20.7065%	$ 7,099,692	61.7767%	$ 21,181,538	FF1 263.5(i)	(1)
										(1)
	Transmission Operation and Maintenance									(1)
7	Operation and Maintenance	$ 362,540,896		$ 362,540,896	20.7065%	$ 75,069,531	61.7767%	$ 223,965,802	FF1 321.112(b)	(1)
8	less: Transmission of Electricity by Others (565)	$ 324,980,606		$ 324,980,606	20.7065%	$ 67,292,109	61.7767%	$ 200,762,294	FF1 321.96(b)	(1)
9	less: Load Dispatching (561 to 561.4)	$ 15,426,418		$ 15,426,418	20.7065%	$ 3,194,271	61.7767%	$ 9,529,932	FF1 321.85(b) through 321.88(b)	(1)
10	less: Rents (567)	$ 14,755		$ 14,755	20.7065%	$ 3,055	61.7767%	$ 9,115	FF1 321.98(b)	(1)
11	O&M for RNS Tariff (line 7 - 8 - 9 - 10)	$ 22,119,117		$ 22,119,117		$ 4,580,096		$ 13,664,461		(1)
										(1)
	Transmission Administrative and General									(1)
12	Administrative and General	$ 145,329,829							FF1 323.197(b)	(1)
13	less: Property Insurance (924)	$ 926,016							FF1 323.185(b)	(1)
14	less: Regulatory Commission Expenses (928)	$ 9,560,209							FF1 323.189(b)	(1)
15	less: Miscellaneous General Expenses (930.2) (d)	$ 52,118							FF1 232.2.14(e)	(1)
16	less: General Advertising Expense (930.1)	$ 32,018							FF1 323.191(b)	(1)
17	Subtotal (line 12 - sum of lines 13 through 16)	$ 134,759,468	10.4993% (b)	$ 14,148,801	20.7065%	$ 2,929,721	61.7767%	$ 8,740,662		(1)
18	plus: Property Insurance (line 13)	$ 926,016	28.4332% (c)	$ 263,296	20.7065%	$ 54,519	61.7767%	$ 162,656	FF1 323.185(b)	(1)
19	plus: Regulatory Comm. Exp (T FERC Assessments)	$ 1,992,376	100.0000%	$ 1,992,376	20.7065%	$ 412,551	61.7767%	$ 1,230,824	FF1 350.6(d)	(1)
20	Total A&G for RNS Tariff (Line 17 + 18 + 19)	$ 137,677,860		$ 16,404,473		$ 3,396,791		$ 10,134,142		(2)
21	Transmission Related Taxes and Fees	$ 1,769,295	28.4332% (c)	$ 503,067	20.7065%	$ 104,168	61.7767%	$ 310,778	FF1 263.8(i)+14(i)+19(i)	(1)
22	Payroll Tax Expense	$ 12,417,455	10.4993% (b)	$ 1,303,746	20.7065%	$ 269,960	61.7767%	$ 805,411	FF1 263.10(i)+15(i)+18(i)	(1)

(a) PTF Allocator (Sheet 6, Line 3)
(b) Wages & Salaries Allocator (Sheet 6, Line 13)
(c) Plant Allocator (Sheet 6, Line 18)
(d) NSTAR Green Program costs are excludable for Transmission billing purposes.

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
Provided this support because these balances will be revised under the changed rates.

Exhibit No. ES-215
Schedule 3

NSTAR Electric's PTF Revenue Requirements under the Changed Rates

Eversource Energy Service Company

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements
Calculated under the Changed Rates in Attachment F of the ISO-NE OATT
For The Calendar Year 2016

	(A)	(B)	(C)
Line	**Description**	**Reference**	**NSTAR Electric**
1	2014 Actual PTF Revenue Requirements	Exhibit No. ES-215, Schedule 3, Page 2 of 5, Line 30, Col.D	$ 225,389,110
2	Estimated 2015 PTF Plant Additions	(1)	$ 146,000,000
3	Carrying Charge Factor (CCF)	Exhibit No. ES-215, Schedule 2, Page 2 of 5, Note (3)	13.89%
4	2015 Incremental Estimated PTF Revenue Requirements	Line 2 x 3	$ 20,279,943
5	2015 Incremental Estimated PTF Intangible Plant Rev. Req.	(1)	$ 343,300
6	Total Estimated PTF Revenue Requirement for 2015	Line 1 + 4 + 5	$ 246,012,353
7	Estimated 2016 PTF Plant Additions	(1)	$ 179,000,000
8	Carrying Charge Factor (CCF)	Line 3	13.89%
9	2016 Incremental Estimated PTF Revenue Requirements	Line 7 x 8	$ 24,863,766
10	Total Estimated PTF Revenue Requirement for 2016	Line 6 + 9	$ 270,876,119

Notes:
(1) Based on Eversource's Forecast

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements
Calculated under the Changed Rates in Attachment F of the ISO-NE OATT
For Costs in 2014
Sheet 2a

Line	Investment Base	Attachment F Reference Section:	Pre-1997	Post-1996	Reference	Notes
	Col.A	Col.B	Col.C	Col.D	Col.E	
1	Transmission Plant	II (A)(1)(a)	$ 394,245,298	$ 1,176,211,529	Sheet 4, line 1	(1)
2	General Plant	II (A)(1)(b)	4,064,182	12,125,263	Sheet 4, line 2	(1)
3	Plant Held For Future Use	II (A)(1)(c)	-	13,571,504	Sheet 4, line 4	(1)
4	**Total Plant** (Line 1 + 2 + 3)		398,309,480	1,201,908,296		
5	Accumulated Depreciation	II (A)(1)(d)	(95,102,434)	(283,732,865)	Sheet 4, line 7	(1)
6	Accumulated Deferred Income Taxes	II (A)(1)(e)	(75,011,955)	(223,794,030)	Sheet 4, line 11	(1)
7	Loss On Reacquired Debt	II (A)(1)(f)	757,488	2,259,924	Sheet 4, line 12	(1)
8	Other Regulatory Assets	II (A)(1)(g)	4,930,985	14,711,323	Sheet 4, line 16	(1)
9	**Net Investment** (Line 4 + 5 + 6 + 7 + 8)		233,883,564	711,352,648		
10	Prepayments	II (A)(1)(h)	2,283,784	6,813,544	Sheet 4, line 17	(1)
11	Materials & Supplies	II (A)(1)(II)	5,909,946	17,631,999	Sheet 4, line 18	(1)
12	Cash Working Capital	II (A)(1)(j)	1,291,286	3,786,998	Sheet 4, line 24	(2)
13	**Total Investment Base** (Line 9 + 10 + 11 + 12)		$ 243,368,580	$ 739,585,189		
	Revenue Requirement					
14	Investment Return and Income Taxes	II (A)	$ 30,225,404	$ 93,329,982	Sheet 3a, Line 26	(2)
15	Depreciation Expense	II (B)	8,679,581	25,895,050	Sheet 5, Line 3	(1)
16	Amortization of Loss on Reacquired Debt	II (C)	58,839	175,544	Sheet 5, Line 4	(1)
17	Investment Tax Credit	II (D)	(77,133)	(230,121)	Sheet 5, Line 5	(1)
18	Property Taxes	II (E)	7,099,692	21,181,538	Sheet 5, Line 6	(1)
19	Payroll tax Expense	II (F)	269,960	805,411	Sheet 5, Line 24	(1)
20	Operation & Maintenance Expense	II (G)	4,580,096	13,664,461	Sheet 5, Line 11	(1)
21	Administrative & General Expense	II (H)	5,574,602	16,631,521	Sheet 5, Line 22	(2)
22	Transmission Related Integrated Facilities Charge	II (I)	-	-	N/A	(1)
23	Transmission Support Revenue	II (J)	(1,153,965)	-	Sheet 7, Line 9	(1)
24	Transmission Support Expense	II (K)	1,329,554	-	Sheet 7, Line 9	(1)
25	Transmission Related Expense from Generators	II (L)	-	-	N/A	(1)
26	Transmission Related Taxes and Fees Charge	II (M)	104,168	310,778	Sheet 5, Line 23	(1)
27	Revenue for ST Trans Service Under NEPOOL Tariff	II (N)	(35,083)	(104,467)	Attachment B, Lines 9 & 10	(1)
28	Transmission Rents Received for Electric Property	II (O)	(2,926,302)	-	Attachment C, Line 3	(1)
29	**Total Revenue Requirements** (Sum of Lines 14 through 28)		$ 53,729,413	$ 171,659,697		
30	**Total Pre-1997 and Post 1996** (Line 29 [Pre-1997 + Post-1996])			$ 225,389,110		

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements
Calculated under the Changed Rates in Attachment F of the ISO-NE OATT
For Costs in 2014
Sheet 3a

Eversource Energy
Exhibit No. ES-215
Schedule 3
Page 3 of 5

Line	Description	Capitalization 12/31/14	Weighted Capitalization	Weighted Cost of Capital (a)	Weighted Cost of Capital	Equity Portion		Notes
	Col.A	Col.B	Col.C	Col.D	Col.E	Col.F		(1)
1	Long-Term Debt	$ 1,792,712,148	41.74%	4.19%	1.75%		FF1 112.24(c)	(1)
2	Preferred Stock	43,000,000	1.00%	4.56%	0.05%	0.05%	FF1 112.3(c)	(1)
3	Common Equity	2,459,452,736	57.26%	11.07%	6.34%	6.34%	FF1 112.16(c) less Line 3(c)	(1)
4	Total Investment Return	$ 4,295,164,884	100.00%		8.14%	6.39%	Sum of Lines 1 to 3	(1)
								(1)

ROE per ISO New England Inc. Transmission, Markets and Services Tariff, Section II Attachment F II.A.2.(iii), page 231 http://www.iso-ne.com/regulatory/tariff/sect_2/oatt/sect_ii.pdf (1)

Line	Description	Pre-97	Post-96		Notes
5	**Federal Income Tax (FIT)**				(1)
6	A= Preferred & Equity Return	6.39%	6.39%	Line 4, Col F	(1)
7	B= Transmission Related Amortization of ITC	$ (77,133)	$ (230,121)	Sheet 2a, Line 17	(1)
8	C= Equity AFUDC Component of Depreciation Expense	$ 18,983	$ 56,635	Sheet 10, Column (g)	(1)
9	D= Transmission Investment Base	$ 243,368,580	$ 739,585,189	Sheet 2a, Line 13	(2)
10	FT = Federal Income Tax Rate	35.00%	35.00%	Federal Income Tax Rate	(1)
11	FIT = (A+[C+B)/D])(FT)/(1-FT)	3.42790%	3.42810%	Federal Income Tax	(1)
12	ST = State Income Tax Rate	8.00%	8.00%	State Tax Rate	(1)
13	**State Income Tax (SIT)**				(1)
14	SIT = (A+[(C+B)/D]+Federal Income Tax)(ST)/(1-ST)	0.8517%	0.8517%	State Income Tax	(1)
15	Allowed Return	12.4196%	12.4198%	line 4, Col.E + Line 11 + Line 14	(1)
16	D= Transmission Investment Base	$ 243,368,580	$ 739,585,189	Sheet 2a, Line 13	(2)
17	**Return**	$ 30,225,404	$ 91,855,001	Line 15 * Line 16	(2)
18	Incremental return for Post 2003 PTF Investment				
19	A= Incremental Return		0.6700%	Per Opinion No. 489 and Opinion No. 531-B (b)	(1)
20	Effective Incremental (a')		0.3800%	line 19 * line 3, Col C	(1)
21	Additional FIT (a'/A')		0.2046%	Incremental FIT = (A' x FT)/(1-FT)	(1)
22	Additional SIT (a'/A')		0.0508%	Incremental SIT = (A' + FIT)(ST)/(1-ST)	(1)
23	Additional Return		0.6354%	Sum lines 20 thru 22	(1)
24	Post 2003 PTF net Investment		$ 232,134,198	Sheet 8, line 15	(1)
25	Additional 100 bp Return Post 2003 PTF Investment		$ 1,474,981	Line 23 * Line 24	(1)
26	Total Return	$ 30,225,404	$ 93,329,982	Line 17 + Line 25	(2)

Line	Description	Capitalization 12/31/14	Weighted Capitalization	Weighted Cost of Capital	Weighted Cost of Capital	Equity Portion	Notes
27	**Incremental return for PTF 50 Basis Point Adder**						
28	Long-Term Debt	$ 1,792,712,148	41.74%	4.19%	1.75%		(1)
29	Preferred Stock	43,000,000	1.00%	4.56%	0.05%		(1)
30	Common Equity	2,459,452,736	57.26%	0.50%	0.29%	0.29%	(1)
31	Total Investment Return	$ 4,295,164,884	100.00%		2.09%	0.29%	(1)

Line	Description	Pre-97	Post-96		Notes
32	**Federal Income Tax (FIT)**				
33	A= Incremental Return	0.29%	0.29%	Line 31, Col F	(1)
34	B= Transmission Related Amortization of ITC	$ -	$ -	N/A	(1)
35	C= Equity AFUDC Component of Depreciation Expense	$ -	$ -	N/A	(1)
36	D= Transmission Investment Base	$ 243,368,580	$ 739,585,189	Sheet 2a, Line 13	(2)
37	FT = Federal Income Tax Rate	35.00%	35.00%	Federal Income Tax Rate	(1)
38	FIT = (A+[C+B)/D])(FT)/(1-FT)	0.15620%	0.15620%	Federal Income Tax	(1)
39	ST = State Income Tax Rate	8.00%	8.00%	State Tax Rate	(1)
40	**State Income Tax (SIT)**				(1)
41	SIT = (A+[(C+B)/D]+Federal Income Tax)(ST)/(1-ST)	0.0388%	0.0388%	State Income Tax	(1)
					(1)
42	Allowed Return	0.4850%	0.4850%	line 33 + Line 38 + Line 41	(1)
43	D= Transmission Investment Base	$ 243,368,580	$ 739,585,189	Sheet 2a, Line 13	(2)
44	Return 50 bp Adder	$ 1,180,338	$ 3,586,988	Line 42 * Line 43	(2)
45	Total Return 50 bp Adder		$ 4,767,326	Line 44 Pre-97 + Line 44 Post 96	(2)
46	Total Incremental Return		$ 6,242,307	Line 25 + Line 45	(2)

(a) See Attachment F for weighted cost of debt and preferred stock support.
(b) As a result of Opinion No. 531-B, these projects receive an ROE incentive of 67 bp.

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements
Calculated under the Changed Rates in Attachment F of the ISO-NE OATT
For Costs in 2014
Sheet 4

Line	Description	Total	Wage/Plant Allocation Factors	Transmission Allocated	Pre-97 PTF Allocation Factor (a)	Pre-97 PTF Allocated	Post-96 PTF Allocation Factor (a)	Post-96 PTF Allocated	Reference	Notes
	Col.A	Col.B	Col.C	Col.D (Col.B x Col.C)	Col.E	Col.F (Col.D x Col.E)	Col.G	Col.H (Col.D x Col.G)	Col.I	(1)
										(1)
	Transmission Plant									(1)
1	Transmission Plant (exc SCADA)	$ 1,903,972,438		$ 1,903,972,438		$ 394,245,298		$ 1,176,211,529	Sheet 6, Line 1 (PTF) & Line 2 (Total)	(1)
2	General Plant	$ 186,941,660	10.4993% (b)	$ 19,627,566	20.7065%	$ 4,064,182	61.7767%	$ 12,125,263	FF1 207.99(g)	(1)
3	Total Transmission Plant (line 1 + 2)			$ 1,923,600,004		$ 398,309,480		$ 1,188,336,792		(1)
										(1)
4	Transmission Plant Held for Future Use	$ 13,571,504	100.0000%	$ 13,571,504	0.0000%	$ -	100.0000%	$ 13,571,504	FF1 214.14(d) to 18(d)	(1)
										(1)
	Transmission Accumulated Depreciation									(1)
5	Transmission Accum. Depreciation	$ (453,776,651)	100.0000%	$ (453,776,651)	20.7065%	$ (93,961,262)	61.7767%	$ (280,328,240)	FF1 219.25(b)	(1)
6	General Plant Accum.Depreciation	$ (52,490,917)	10.4993% (b)	$ (5,511,179)	20.7065%	$ (1,141,172)	61.7767%	$ (3,404,625)	FF1 219.28(b)	(1)
7	Total Transmission Acc Dep (line 5 + 6)			$ (459,287,830)		$ (95,102,434)		$ (283,732,865)		(1)
										(1)
	Transmission Accumulated Deferred Taxes									(1)
8	Accumulated Deferred Taxes (282) (d)	$ (1,143,462,163)	28.4332% (c)	$ (325,122,884)	20.7065%	$ (67,321,570)	61.7767%	$ (200,850,189)	FF1 275.9(k) - 275.4(k)	(1)
9	Accumulated Deferred Taxes (283)			$ (45,243,071)	20.7065%	$ (9,368,256)	61.7767%	$ (27,949,676)	Sheet 9, Line 25, Col D	(1)
10	Accumulated Deferred Taxes (190)			$ 8,103,112	20.7065%	$ 1,677,871	61.7767%	$ 5,005,835	Sheet 9, Line 10, Col D	(1)
11	Total ADIT (line 8 + 9 + 10)			$ (362,262,843)		$ (75,011,955)		$ (223,794,030)		(1)
										(1)
12	Transmission loss on Reacquired Debt	$ 12,865,994	28.4332% (c)	$ 3,658,214	20.7065%	$ 757,488	61.7767%	$ 2,259,924	FF1 111.81(c)	(1)
										(1)
	Other Regulatory Assets									(1)
13	FAS 106	$ -	10.4993% (b)	$ -					FF1 232	(1)
14	ASC 740 Regulatory Asset (FAS 109)	$ 87,768,732	28.4332% (c)	$ 24,955,459					FF1 232.29(f)	(1)
15	ASC 740 Regulatory Liability (FAS 109)	$ (4,015,556)	28.4332% (c)	$ (1,141,751)					FF1 278.2(f)	(1)
16	Total (line 13 + 14 + 15)	$ 83,753,176		$ 23,813,708	20.7065%	$ 4,930,985	61.7767%	$ 14,711,323		(1)
										(1)
17	Transmission Prepayments	$ 105,048,059	10.4993% (b)	$ 11,029,311	20.7065%	$ 2,283,784	61.7767%	$ 6,813,544	FF1 111.57(c)	(1)
										(1)
18	Transmission Materials and Supplies	$ 28,541,503	100.0000%	$ 28,541,503	20.7065%	$ 5,909,946	61.7767%	$ 17,631,999	FF1 227.8(c) + 227.5(c) Footnote	(1)
	Cash Working Capital									
19	Operation & Maintenance Expense					$ 4,580,096		$ 13,664,461	Sheet 5, line 11	
20	Administrative & General Expense					$ 5,574,602		$ 16,631,521	Sheet 5, line 22	(2)
21	Net Transmission Support Expense					$ 175,589		$ -	Sheet 7, line 9	(1)
22	Total (line 19 + 20 + 21)					$ 10,330,287		$ 30,295,982		(2)
23	45 day allowance per tariff					0.1250		0.1250	= 45 days / 360 days	(1)
24	Cash Working Capital (line 22 * 23)					$ 1,291,286		$ 3,786,998		(2)

(a) PTF Allocator (Sheet 6, Line 3)
(b) Wages & Salaries Allocator (Sheet 6, Line 13)
(c) Plant Allocator (Sheet 6, Line 18)
(d) ADIT in FERC Account 282 excludes ADIT associated with transition property from FF1 275.4(k)

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements
Calculated under the Changed Rates in Attachment F of the ISO-NE OATT
For Costs in 2014
Sheet 5

Line	Description	Total	Wage/Plant Allocation Factors		Transmission Allocated	Pre-97 PTF Allocation Factor (a)	Pre-97 PTF Allocated	Post-96 PTF Allocation Factor (a)	Post-96 PTF Allocated	Reference	Notes
	Col.A	Col.B	Col.C		Col.D (Col.B x Col.C)	Col.E	Col.F (Col.D x Col.E)	Col.G	Col.H (Col.D x Col.G)	Col.I	
	Depreciation Expense										
1	Transmission Depreciation	$ 41,001,613			$ 41,001,613	20.7065%	$ 8,489,999	61.7767%	$ 25,329,443	FF1 336.7(b)	(1)
2	General Depreciation	$ 8,720,270	10.4993%	(b)	$ 915,567	20.7065%	$ 189,582	61.7767%	$ 565,607	FF1 336.10(b)	(1)
3	Total (line 1 + 2)	$ 49,721,883			$ 41,917,180		$ 8,679,581		$ 25,895,050		(1)
											(1)
4	Amortization of Loss on Reacquired Debt	$ 999,391	28.4332%	(c)	$ 284,159	20.7065%	$ 58,839	61.7767%	$ 175,544	FF1 117.64(c)	(1)
											(1)
5	Amortization of Investment Tax Credits	$ 1,310,106	28.4332%	(c)	$ 372,505	20.7065%	$ 77,133	61.7767%	$ 230,121	FF1 114.19(c)	(1)
											(1)
	Property Taxes										(1)
6	Transmission Property Taxes	$ 120,588,821	28.4332%	(c)	$ 34,287,261	20.7065%	$ 7,099,692	61.7767%	$ 21,181,538	FF1 263.5(i)	(1)
											(1)
	Transmission Operation and Maintenance										(1)
7	Operation and Maintenance	$ 362,540,896			$ 362,540,896	20.7065%	$ 75,069,531	61.7767%	$ 223,965,802	FF1 321.112(b)	(1)
8	less: Transmission of Electricity by Others (565)	$ 324,980,606			$ 324,980,606	20.7065%	$ 67,292,109	61.7767%	$ 200,762,294	FF1 321.96(b)	(1)
9	less: Load Dispatching (561 to 561.4)	$ 15,426,418			$ 15,426,418	20.7065%	$ 3,194,271	61.7767%	$ 9,529,932	FF1 321.85(b) through 321.88(b)	(1)
10	less: Rents (567)	$ 14,755			$ 14,755	20.7065%	$ 3,055	61.7767%	$ 9,115	FF1 321.98(b)	(1)
11	O&M for RNS Tariff (line 7 - 8 - 9 - 10)	$ 22,119,117			$ 22,119,117		$ 4,580,096		$ 13,664,461		(1)
											(1)
	Transmission Administrative and General										(1)
12	Administrative and General	$ 145,329,829								FF1 323.197(b)	(1)
13	less: Property Insurance (924)	$ 926,016								FF1 323.185(b)	(1)
14	less: Regulatory Commission Expenses (928)	$ 9,560,209								FF1 323.189(b)	(1)
15	less: Miscellaneous General Expenses (930.2) (d)	$ 52,118								FF1 232.2.14(e)	(1)
16	less: General Advertising Expense (930.1)	$ 32,018								FF1 323.191(b)	(1)
17	less: Merger-Related Costs	$ -									(2)
18	Subtotal (line 12 - sum of lines 13 through 16)	$ 134,759,468	10.4993%	(b)	$ 14,148,801	20.7065%	$ 2,929,721	61.7767%	$ 8,740,662		(1)
19	plus: Property Insurance (line 13)	$ 926,016	28.4332%	(c)	$ 263,296	20.7065%	$ 54,519	61.7767%	$ 162,656	FF1 323.185(b)	(1)
20	plus: Regulatory Comm. Exp (T FERC Assessments)	$ 1,992,376	100.0000%		$ 1,992,376	20.7065%	$ 412,551	61.7767%	$ 1,230,824	FF1 350.6(d)	(1)
21	plus: Transmission Merger-Related Costs	$ 10,517,524	100.0000%		$ 10,517,524	20.7065%	$ 2,177,811	61.7767%	$ 6,497,379	**Exhibit No. ES-201, Page 1 of 1, Ln.24 (H)**	(2)
22	Total A&G for RNS Tariff (Line 17 + 18 + 19)	$ 148,195,384			$ 26,921,997		$ 5,574,602		$ 16,631,521		(2)
23	Transmission Related Taxes and Fees	$ 1,769,295	28.4332%	(c)	$ 503,067	20.7065%	$ 104,168	61.7767%	$ 310,778	FF1 263.8(i)+14(i)+19(i)	(1)
24	Payroll Tax Expense	$ 12,417,455	10.4993%	(b)	$ 1,303,746	20.7065%	$ 269,960	61.7767%	$ 805,411	FF1 263.10(i)+15(i)+18(i)	(1)

(a) PTF Allocator (Sheet 6, Line 3)
(b) Wages & Salaries Allocator (Sheet 6, Line 13)
(c) Plant Allocator (Sheet 6, Line 18)
(d) NSTAR Green Program costs are excludable for Transmission billing purposes.

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Exhibit No. ES-216
Schedule 1

Summary of Impact on NSTAR Electric SCADA Revenue Requirements under Schedule 1, Appendix A of the ISO-NE OATT (1-year amortization)

Eversource Energy Service Company

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
SCADA Revenue Requirement Comparison Under Present and Changed rates
Under Schedule 1, Appendix A
For the Calendar year 2016

	(A)	(B)		(C)		(D) = (C - (B)		(E) = (D)/(B)
Line	**Description**	**Total Schedule 1 Revenue Requirements under present rates in Appendix A**		**Total Schedule 1 Revenue Requirements under changed rates in Appendix A**		**Difference**		**% Difference**
1	2016 Estimated Schedule 1 Revenue Requirements	$ 6,785,703	(1)	$ 6,858,305	(2)	$ 73,000	(3)	1.1%

Notes:

(1) Exhibit No. ES-216, Schedule 2, Page 1 of 6, Line 9(C)
(2) Exhibit No. ES-216, Schedule 3, Page 1 of 6, Line 9(C)
(3) In connection with the one-year amortization proposal (with the proposed effective date of June 1, 2016), Eversource is showing the revenue impact for the twelve-month period June 1, 2016 through May 31, 2017. Eversource is using revenue requirement calculations for the calendar year 2016 as an estimate for the twelve-month period beginning June 1, 2016. See Cooper Testimony Exhibit No. ES-200.

	2016	**2017**	**Total**
The amounts for each year are as follows:	$ 42,583	$ 30,417	$ 73,000

Exhibit No. ES-216
Schedule 2

SCADA Revenue Requirements under Present Rates for the Calendar Year 2016

Eversource Energy Service Company

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated SCADA Revenue Requirements Under Present Rates
Under Schedule 1, Appendix A
For the Calendar year 2016

	(A)	(B)	(C)
Line	**Description**	**Reference**	**Total NSTAR Electric**
1	2014 Actual SCADA Revenue Requirement	Exhibit No. ES-216, Schedule 2, Page 2 of 6, Line 26(c)	$ 6,785,703
2	Estimated 2015 SCADA Plant Additions	(1)	$ -
3	Carrying Charge Factor (CCF)	(1)	0.00%
4	2015 Incremental Estimated SCADA Revenue Requirement	Line 2 x 3	-
5	Total Estimated SCADA Revenue Requirement for 2015	Line 1 + 4	$ 6,785,703
6	Estimated 2016 SCADA Plant Additions	(1)	$ -
7	Carrying Charge Factor (CCF)	(1)	0.00%
8	2016 Incremental Estimated SCADA Revenue Requirement	Line 6 x 7	-
9	Total Estimated SCADA Revenue Requirement for 2016	Line 5 + 8	$ 6,785,703

Notes:
(1) There are no forecasted SCADA plant additions

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated SCADA Revenue Requirements Under Present Rates
Under Schedule 1, Appendix A
Total Revenue Requirements For the Calendar year 2014
Sheet 1

	(a)	(b)	(c)		(d)	(e)
Line	Description	Tariff Section	Amount		Reference	Notes
1	Dispatch Center Investment Base	A.1				
2	Dispatch Center Plant	A.1.a	$	11,320,255	Sheet 3, Line 1(f)	(1)
3	Dispatch Center Related General Plant	A.1.b	$	4,463,606	Sheet 3, Line 2(f)	(1)
4	Dispatch Center Plant Held for Future Use	A.1.c	$	-	Sheet 3, Line 3(f)	(1)
5	Total Plant (line 2 + 3 + 4)		$	15,783,861		
6	Dispatch Center Related Depreciation Reserve	A.1.d	$	6,017,455	Sheet 3, Line 7(f)	(1)
7	Dispatch Center Related Accumulated Deferred Taxes	A.1.e	$	4,962,888	Sheet 3, Line 13(f)	(1)
8	Total Net Plant (line 5 - 6 - 7)		$	4,803,518		
9	Other Regulatory Assets	A.1.f	$	195,396	Sheet 3, Line 18(f)	(1)
10	Dispatch Center Prepayments	A.1.g	$	2,508,233	Sheet 3, Line 19(f)	(1)
11	Disptach Center Materials & Supplies	A.1.h	$	66,587	Sheet 3, Line 20(f)	(1)
12	Dispatch Center Related Cash Working Capital	A.1.i	$	811,948	Sheet 3, Line 24(f)	(2)
13	Total Dispatch Center Investment Base (sum of lines [8-12])		$	8,385,682		
14	Revenue Requirements					
15	Investment Return and Income Taxes	A.2	$	1,042,064	Sheet 2, Line 38(c)	(2)
16	Disptach Center Depreciation Expense	B	$	484,934	Sheet 4, Line 4(f)	(1)
17	Dispatch Center Related Amortization of Investment Tax Credits	C	$	(3,056)	Sheet 4, Line 5(f)	(1)
18	Dispatch Center Related Municipal Tax Expense	D	$	281,334	Sheet 4, Line 6(f)	(1)
19	Dispatch Center Related Payroll Tax Expense	E	$	296,376	Sheet 4, Line 7(f)	(1)
20	Dispatch Center Operation & Maintenance Expense	F	$	3,271,123	Sheet 4, Line 14(f)	(1)
21	Dispatch Center Related Administrative and General Expenses	G	$	3,224,460	Sheet 4, Line 24(f)	(2)
22	Total Revenue Requirements (sum of lines [15-21])		$	8,597,235		
23	PTF Transmission Plant Allocator			82.4832%	NSTAR PTF Sheet 6, Line 4	(1)
24	PTF Revenue Requirement for SCADA (line 22 * 24)		$	7,091,275		
25	PTF Transmission Plant Allocator			(305,572)	Exhibit 1	(1)
26	PTF Revenue Requirement for SCADA (line 22 * 24)		$	6,785,703		

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.

(2) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000. Provided this support because these balances will be revised under the changed rates.

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated SCADA Revenue Requirements Under Present Rates
Under Schedule 1, Appendix A
Investment Return and Income Tax Calculation For the Calendar year 2014
Sheet 2

Line	(a) Description	(b) Tariff Section	(c) Balance	(d) Capitalization Ratio	(e) Cost	(f) Weighted Cost	(g) Equity Cost	(h) Reference	(I) Notes
1	Weighted Cost of Capital	A.2.a							
2	Long Term Debt	A.2 a.i	$ 1,792,712,148	41.74%	4.22%	1.76%		Page 112.24(c)	(1)
3	Preferred Stock	A.2.a.ii	$ 43,000,000	1.00%	4.56%	0.05%	0.05%	Page 112.3(c)	(1)
4	Common Equity	A.2.a.iii	$ 2,459,452,736	57.26%	11.07%	6.34%	6.34%	Page 112.16(c) (less Line 3)	(1)
5	Total (line 2 + 3 + 4)		$ 4,295,164,884	100 00%		8.15%	6.39%		
6	Total Investment Base		$ 8,385,682					Sheet 1, Line 13(c)	(2)
7	Weighted Cost of Capital		8.15%					Line 5(f)	
8	Total Return on Investment		$ 683,433					Line 6 * Line 7	
9	Federal Income Tax	A 2.b							
10	A = Equity Cost		6.39%					Line 5(g)	
11	B = Transmission Amortization of ITC		$ (3,056)					Sheet 4, Line 5(f)	(1)
12	C = Equity AFUDC		$ 700						
13	Total B + C		$ (2,356)					Line 11 + Line 12	
14	D = Investment Base		$ 8,385,682					Line 6	(2)
15	(B + C) / D		-0.0281%					Line 13 / Line 14	(2)
16	(A + [(C + B) / D])		6.3619%					Line 10 + Line 15	(2)
17	FT = Federal Income Tax Rate		35.00%						
18	1 - FT		65.00%					1 - Line 17	
19	Federal Tax Factor		3.4256%					Line 16 * Line 17 / Line 18	
20	Total Federal Income Taxes		$ 287,260					Line 14 * Line 19	
21	State Income Tax	A.2.c							
22	A = Equity Cost		6.39%					Line 5(g)	
23	B = Transmission Amortization of ITC		$ (3,056)					Sheet 4, Line 5(f)	(1)
24	C = Equity AFUDC		$ 700.00						
25	Total B + C		$ (2,356)					Line 23 + Line 24	
26	D = Investment Base		$ 8,385,682					Line 6	(2)
27	(B + C) / D		-0.0281%					Line 25 / Line 26	(2)
28	(A + [(C + B) / D])		6.3619%					Line 22 + Line 27	(2)
29	ST = State Income Tax Rate		8.00%						
30	1 - ST		92.00%					1 - Line 29	
31	Federal Tax Factor		3.4256%					Line 19	
32	State Tax Factor		0.8511%					(Line 28 + Line 31) * Line 29 / Line 30	
33	Total State Income Taxes		$ 71,371					Line 26 * Line 32	
34	Investment Return and Income Taxes	A.2							
35	Return on Investment		$ 683,433					Line 8	(2)
36	Federal Income Taxes		$ 287,260					Line 20	(2)
37	State Income Taxes		$ 71,371					Line 33	(2)
38	Total Investment Return and Income Taxes		$ 1,042,064					Sum Lines 35 thru 37	(2)
39	Value of 50BP ROE Adder								
40	ROE Adder		0.50%					Per Tariff	
41	Equity Ratio		57.26%					Line 4(d)	
42	Effective Adder		0.29%					Line 40 * Line 41	
43	Tax Gross-up		0.1949%					Line 42 * .6722408	
44	Adder plus Gross-up		0.4849%					Line 42 + Line 43	
45	Rate Base		$ 8,385,682					Line 6	
46	Earned Adder		$ 40,662					Line 44 * Line 45	
47	PTF Ratio		82.4832%					RNS Sheet 6	(1)
48	PTF Related Adder		$ 33,539					Line 46 * Line 47	

Notes

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.

(2) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000. Provided this support because these balances will be revised under the changed rates.

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated SCADA Revenue Requirements Under Present Rates
Under Schedule 1, Appendix A
Rate Base Items For the Calendar year 2014
Sheet 3

Line	(a) Description	(b) Tariff Section	(c) Total	(d) Allocator	(e) Allocation Factor	(f) Dispatch Center Allocated	(g) Reference	(h) Notes
1	Dispatch Center Plant	A.1.a				$ 11,320,255	Sheet 6, Line 12(c)	(1)
2	Dispatch Center Related General Plant	A.1.b	$ 186,941,660	W&S	2.3877%	$ 4,463,606	FF1 207.99(g)	(1)
3	Dispatch Center Plant Held for Future Use	A.1.c				$ -	FF1 214	(1)
4	Dispatch Center Related Depreciation Reserve	A.1.d						
5	Dispatch Center Depreciation Reserve					$ 4,764,129	FF1 219.25(b) (part)	(1)
6	Transmission Related General Depreciation Reserve		$ 52,490,917	W&S	2.3877%	$ 1,253,326	FF1 219.28(b)	(1)
7	Total Dispatch Center Related Depreciation Reserve (line 5 6)					$ 6,017,455		
8	Dispatch Center Related Accumulated Deferred Taxes	A.1.e						
9	ADIT - Accelerated Amortization Property (Acct #281)		$ -	Plant	0.2333%	$ -	FF1 273.17(k)	(1)
10	ADIT - Other Property (Acct #282)		$ 1,143,462,163	Plant	0.2333%	$ 2,667,697	Line 27	(1)
11	ADIT - Other (Acct #283)					$ 2,876,873	Sheet 7, Line 30(d)	(1)
12	Less ADIT (Acct #190)					$ 581,682	Sheet 7, Line 12(d)	(1)
13	Total Dispatch Center Related ADIT (ine 9 10 11 - 12)					$ 4,962,888		
14	Other Regulatory Assets	A.1.f						
15	FAS 106		$ -	W&S	2.3877%	$ -	FF1 232.1	(1)
16	ASC 740 Regulatory Asset (FAS 109)		$ 87,768,732	Plant	0.2333%	$ 204,764	FF1 232.29(f)	(1)
17	Less ASC 740 Regulatory Liability (FAS 109)		$ 4,015,556	Plant	0.2333%	$ 9,368	FF1 278.1(f)	(1)
18	Total Other Regulatory Assets (line 15 16 - 17)		$ 83,753,176			$ 195,396		
19	Dispatch Center Prepayments	A.1.g	$ 105,048,059	W&S	2.3877%	$ 2,508,233	FF1 111.57(c)	(1)
20	Dispatch Center Materials and Supplies	A.1.h	$ 28,541,503	Plant	0.2333%	$ 66,587	FF1 227.8(c) + 5(c) fn	(1)
21	Dispatch Center Related Cash Working Capital	A.1.i						
22	Dispatch Center Operation and Maintenance Expense		$ 3,271,123	WC	12.50%	$ 408,890	Sheet 4, Line 14(f)	(1)
23	Dispatch Center Related Administrative and General Expense		$ 3,224,460	WC	12.50%	$ 403,058	Sheet 4, Line 24(f)	(2)
24	Total Dispatch Center Related Cash Working Capital (line 22 23)		$ 6,495,583			$ 811,948		
25	Account 282		$ 1,143,462,163	FF1 275.9(k)				
26	less amounts related to divestiture		$ -	FF1 275.4(k)				
27	Total Account 282 (line 25 26)		$ 1,143,462,163					

Notes:

Line	Description	Allocation Factor	Reference	
28	Wages & Salary Allocation (W&S)	2.3877%	Sheet 6, Line 6(c)	(1)
29	Plant Allocation Allocation (Plant)	0.2333%	Sheet 6, Line 16(c)	(1)
30	Cash Working Capital (WC)	12.50%	OATT - Schedule 1, A.1.i	(1)

Notes:

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(2) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
Provided this support because these balances will be revised under the changed rates.

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated SCADA Revenue Requirements Under Present Rates
Under Schedule 1, Appendix A
Expense Items For the Calendar year 2014
Sheet 4

Line	(a) Description	(b) Tariff Section	(c) Total	(d) Allocator	(e) Allocation Factor	(f) = (c) * (e) Dispatch Center Allocated	(g) Reference	(h) Notes
1	Dispatch Center Depreciation Expense	B						
2	Dispatch Center Plant Depreciation Expense					$ 276,720	See Line 31(d)	(1)
3	General Plant Depreciation Expense		$ 8,720,270	W&S	2.3877%	$ 208,214	FF1 336.10(b)	(1)
4	Total Dispatch Center Depreciation Expense (line 2 3)					$ 484,934		
5	Dispatch Center Related Amortization of Investment Tax Credits	C	$ (1,310,106)	Plant	0.2333%	$ (3,056)	FF1 266.8(f) & 11(f)	(1)
6	Dispatch Center Related Municipal Tax Expense	D	$ 120,588,821	Plant	0.2333%	$ 281,334	FF1 263.5(i)	(1)
7	Dispatch Center Related Payroll Tax Expense	E	$ 12,412,619	W&S	2.3877%	$ 296,376	FF1 263.10(i)	(1)
8	Dispatch Center Operations & Maintenance Expense	F						
9	Load dispatching #561		$ -	Direct	100.0000%	$ -	FF1 321.84(b)	(1)
10	Load dispatching - Reliability #561.1		$ 1,389,220	Direct	100.0000%	$ 1,389,220	FF1 321.85(b)	(1)
11	Load dispatching - Mon & Oper Trans System 561.2		$ 1,311,222	Direct	100.0000%	$ 1,311,222	FF1 321.86(b)	(1)
12	Load dispatching - Trans Service & Scheduling #561.3		$ 570,681	Direct	100.0000%	$ 570,681	FF1 321.87(b)	(1)
13	Scheduling, System Control and Dispatch Services #561.4		$ 12,155,295		0%	$ -	FF1 321.88(b)	(1)
14	Total Dispatch Center O&M Expense (sum of lines [9-13])		$ 15,426,418			$ 3,271,123		
15	Dispatch Center Related Administrative & General Expenses	G						
16	Administrative and General Expenses		$ 145,329,829				FF1 323.197(b)	(2)
17	less: Property Insurance (Acct #924)		$ 926,016				FF1 323.185(b)	(1)
18	less: Regulatory Commission Expenses (Acct #928)		$ 9,560,209				FF1 323.189(b)	(1)
19	less: General Advertising Expenses (Acct #930.1)		$ 32,018				FF1 323.191(b)	(1)
20	less: Miscellaneous General Expenses (Acct #930.2) '(1)		$ 52,118				FF1 323.192(b) fn	(1)
21	Subtotal (line 16 - sum of lines[17-20])		$ 134,759,468	W&S	2.3877%	$ 3,217,652		
22	Property Insurance		$ 926,016	Plant	0.2333%	$ 2,160	FF1 323.185(b)	(1)
23	FERC Assessments in Regulatory Commission Expenses (Acct #928)		$ 1,992,376	Plant	0.2333%	$ 4,648	FF1 350.7(d)	(1)
24	Total Dispatch Center Related A&G Expenses (sum of lines [21-23])		$ 137,677,860			$ 3,224,460		

NOTES:

Line	Description	Allocation Factor	Reference	Notes
25	Direct Allocation (Direct)	100.0000%		(1)
26	Wages & Salaries Allocation (W&S)	2.3877%	Sheet 6, Line 6(c)	(1)
27	Plant Allocation (Plant)	0.2333%	Sheet 6, Line 16(c)	(1)

Line	Description	Total Investment	Life Depr. Rate	Depreciation Expense	Reference	Notes
28	Mass. Ave. Service Center - 431 (Trans. Station Equipment)	$ 7,966,151	2.53%	$ 201,464	Sheet 6, Line 9(c)	(1)
29	SCADA Mass. Ave. - 421 (Trans. & Conversion Station Structures)	$ 2,816,142	2.19%	$ 61,646	Sheet 6, Line 10(c)	(1)
30	SCADA Mass. Ave. - 431 (Trans. Station Equipment)	$ 537,962	2.53%	$ 13,610	Sheet 6, Line 11(c)	(1)
31	Total	$ 11,320,255		$ 276,720	Sum Lines 28 thru 30	

(1) NSTAR Green Program costs are excludable for Transmission billing purposes. Reflects actual information per Eversource's accounting records.

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.

(2) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000. Provided this support because these balances will be revised under the changed rates.

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated SCADA Revenue Requirements Under Present Rates
Under Schedule 1, Appendix A
Allocation Calculations For the Calendar year 2014
Sheet 6

Line	(a) Description	(b) Tariff Section	(c) Amount	(d) Reference	(e) Notes
1	Dispatch Center Wages & Salaries Allocation Factor	Definitions			
2	Direct Dispatch Center Wages & Salaries		$ 2,858,118	Note (a)	(1)
3	NSTAR Electric Direct Wages & Salaries		$ 152,023,518	FF1 354.28(b)	(1)
4	Less: Administrative & General Wages & Salaries		$ 32,322,705	FF1 354.27(b)	(1)
5	Net NSTAR Electric Wages & Salaries (line 3 - 4)		$ 119,700,813		
6	Wages & Salaries Allocation Factor (line 2 / 5)		2.3877%		
7	Dispatch Center Plant Allocation Factor	Definitions			
8	Investment In Dispatch Center Plant				
9	Mass. Ave. Service Center - 431 (Trans. Station Equipment)		$ 7,966,151	Note (a)	(1)
10	SCADA Mass. Ave. - 421 (Trans. & Conversion Station Structures)		$ 2,816,142		(1)
11	SCADA Mass. Ave. - 431 (Trans. Station Equipment)		$ 537,962		(1)
12	Total Investment in Dispatch Center Plant (line 9 + 10 + 11)		$ 11,320,255		
13	Dispatch Center Related General Plant		$ 4,463,606	Sheet 3, Line 2(f)	(1)
14	Total Dispatch Center Plant Investment (line 12 + 13)		$ 15,783,861		
15	Total Plant in Service		$ 6,765,341,609	FF1 207.104(g)	(1)
16	Plant Allocation Factor (line 14 / 15)		0.2333%		

Note (a): Reflects actual information per Eversource's accounting records.

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.

(2) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000. Provided this support because a new allocation factor is calculated under changed rates

Exhibit No. ES-216
Schedule 3

SCADA Revenue Requirements under Changed Rates for the Calendar Year 2016

Eversource Energy Service Company

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated SCADA Revenue Requirement Under Changed Rates
Under Schedule 1, Appendix A
For the Calendar year 2016

	(A)	(B)	(C)
Line	**Description**	**Reference**	**Total NSTAR Electric**
1	2014 Actual SCADA Revenue Requirement	Exhibit No. ES-216, Schedule 3, Page 2 of 6, Line 26(c)	$ 6,858,305
2	Estimated 2015 SCADA Plant Additions	(1)	$ -
3	Carrying Charge Factor (CCF)	(1)	0.00%
4	2015 Incremental Estimated SCADA Revenue Requirement	Line 2 x 3	-
5	Total Estimated SCADA Revenue Requirement for 2015	Line 1 + 4	$ 6,858,305
6	Estimated 2016 SCADA Plant Additions	(1)	$ -
7	Carrying Charge Factor (CCF)	(1)	0.00%
8	2016 Incremental Estimated SCADA Revenue Requirement	Line 6 x 7	-
9	Total Estimated SCADA Revenue Requirement for 2016	Line 5 + 8	$ 6,858,305

Notes:
(1) There are no forecasted SCADA plant additions

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated SCADA Revenue Requirement Under Changed Rates
Under Schedule 1, Appendix A
Total Revenue Requirements For the Calendar year 2014
Sheet 1

Line	(a) Description	(b) Tariff Section		(c) Amount	(d) Reference	(e) Notes
1	Dispatch Center Investment Base	A.1				
2	Dispatch Center Plant	A.1.a	$	11,320,255	Sheet 3, Line 1(f)	(1)
3	Dispatch Center Related General Plant	A.1.b	$	4,463,606	Sheet 3, Line 2(f)	(1)
4	Dispatch Center Plant Held for Future Use	A.1.c	$	-	Sheet 3, Line 3(f)	(1)
5	Total Plant (line 2 + 3 + 4)		$	15,783,861		
6	Dispatch Center Related Depreciation Reserve	A.1.d	$	6,017,455	Sheet 3, Line 7(f)	(1)
7	Dispatch Center Related Accumulated Deferred Taxes	A.1.e	$	4,962,888	Sheet 3, Line 13(f)	(1)
8	Total Net Plant (line 5 - 6 - 7)		$	4,803,518		
9	Other Regulatory Assets	A.1.f	$	195,396	Sheet 3, Line 18(f)	(1)
10	Dispatch Center Prepayments	A.1.g	$	2,508,233	Sheet 3, Line 19(f)	(1)
11	Disptach Center Materials & Supplies	A.1.h	$	66,587	Sheet 3, Line 20(f)	(1)
12	Dispatch Center Related Cash Working Capital	A.1.i	$	822,782	Sheet 3, Line 24(f)	(2)
13	Total Dispatch Center Investment Base (sum of lines [8-12])		$	8,396,516		
14	Revenue Requirements					
15	Investment Return and Income Taxes	A.2	$	1,043,410	Sheet 2, Line 38(c)	(2)
16	Disptach Center Depreciation Expense	B	$	484,934	Sheet 4, Line 4(f)	(1)
17	Dispatch Center Related Amortization of Investment Tax Credits	C	$	(3,056)	Sheet 4, Line 5(f)	(1)
18	Dispatch Center Related Municipal Tax Expense	D	$	281,334	Sheet 4, Line 6(f)	(1)
19	Dispatch Center Related Payroll Tax Expense	E	$	296,376	Sheet 4, Line 7(f)	(1)
20	Dispatch Center Operation & Maintenance Expense	F	$	3,271,123	Sheet 4, Line 14(f)	(1)
21	Dispatch Center Related Administrative and General Expenses	G	$	3,311,135	Sheet 4, Line 26(f)	(2)
22	Total Revenue Requirements (sum of lines [15-21])		$	8,685,256		
23	PTF Transmission Plant Allocator			82.4832%		(1)
24	PTF Revenue Requirement for SCADA (line 22 * 24)		$	7,163,877		
25	PTF Transmission Plant Allocator			(305,572)	Exhibit 1	(1)
26	PTF Revenue Requirement for SCADA (line 22 * 24)		$	6,858,305		

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.

(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated SCADA Revenue Requirement Under Changed Rates
Under Schedule 1, Appendix A
Investment Return and Income Tax Calculation For the Calendar year 2014
Sheet 2

Line	(a) Description	(b) Tariff Section	(c) Balance	(d) Capitalization Ratio	(e) Cost	(f) Weighted Cost	(g) Equity Cost	(h) Reference	(I) Notes
1	Weighted Cost of Capital	A.2.a							
2	Long Term Debt	A.2 a.i	$ 1,792,712,148	41.74%	4.22%	1.76%		Page 112.24(c)	(1)
3	Preferred Stock	A.2.a.ii	$ 43,000,000	1.00%	4.56%	0.05%	0.05%	Page 112.3(c)	(1)
4	Common Equity	A.2.a.iii	$ 2,459,452,736	57.26%	11.07%	6.34%	6.34%	Page 112.16(c) (less Line 3)	(1)
5	Total (line 2 + 3 + 4)		$ 4,295,164,884	100 00%		8.15%	6.39%		
6	Total Investment Base		$ 8,396,516					Sheet 1, Line 13(c)	(2)
7	Weighted Cost of Capital		8.15%					Line 5(f)	
8	Total Return on Investment		$ 684,316					Line 6 * Line 7	
9	Federal Income Tax	A 2.b							
10	A = Equity Cost		6.39%					Line 5(g)	
11	B = Transmission Amortization of ITC		$ (3,056)					Sheet 4, Line 5(f)	(1)
12	C = Equity AFUDC		$ 700						
13	Total B + C		$ (2,356)					Line 11 + Line 12	
14	D = Investment Base		$ 8,396,516					Line 6	(2)
15	(B + C) / D		-0.0281%					Line 13 / Line 14	(2)
16	(A + [(C + B) / D])		6.3619%					Line 10 + Line 15	(2)
17	FT = Federal Income Tax Rate		35.00%						
18	1 - FT		65.00%					1 - Line 17	
19	Federal Tax Factor		3.4256%					Line 16 * Line 17 / Line 18	
20	Total Federal Income Taxes		$ 287,631					Line 14 * Line 19	
21	State Income Tax	A.2.c							
22	A = Equity Cost		6.39%					Line 5(g)	
23	B = Transmission Amortization of ITC		$ (3,056)					Sheet 4, Line 5(f)	(1)
24	C = Equity AFUDC		$ 700.00						
25	Total B + C		$ (2,356)					Line 23 + Line 24	
26	D = Investment Base		$ 8,396,516					Line 6	(2)
27	(B + C) / D		-0.0281%					Line 25 / Line 26	(2)
28	(A + [(C + B) / D])		6.3619%					Line 22 + Line 27	(2)
29	ST = State Income Tax Rate		8.00%						
30	1 - ST		92.00%					1 - Line 29	
31	Federal Tax Factor		3.4256%					Line 19	
32	State Tax Factor		0.8511%					(Line 28 + Line 31) * Line 29 / Line 30	
33	Total State Income Taxes		$ 71,463					Line 26 * Line 32	
34	Investment Return and Income Taxes	A.2							
35	Return on Investment		$ 684,316					Line 8	(2)
36	Federal Income Taxes		$ 287,631					Line 20	(2)
37	State Income Taxes		$ 71,463					Line 33	(2)
38	Total Investment Return and Income Taxes		$ 1,043,410					Sum Lines 35 thru 37	(2)
39	Value of 50BP ROE Adder								
40	ROE Adder		0.50%					Per Tariff	
41	Equity Ratio		57.26%					Line 4(d)	
42	Effective Adder		0.29%					Line 40 * Line 41	
43	Tax Gross-up		0.1949%					Line 42 * .6722408	
44	Adder plus Gross-up		0.4849%					Line 42 + Line 43	
45	Rate Base		$ 8,396,516					Line 6	
46	Earned Adder		$ 40,715					Line 44 * Line 45	
47	PTF Ratio		82.4832%					RNS Sheet 6	(1)
48	PTF Related Adder		$ 33,583					Line 46 * Line 47	

Notes

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.

(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated SCADA Revenue Requirement Under Changed Rates
Under Schedule 1, Appendix A
Rate Base Items For the Calendar year 2014
Sheet 3

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Line	Description	Tariff Section	Total	Allocator	Allocation Factor	Dispatch Center Allocated	Reference	Notes
1	Dispatch Center Plant	A.1.a				$ 11,320,255	Sheet 6, Line 12(c)	(1)
2	Dispatch Center Related General Plant	A.1.b	$ 186,941,660	W&S	2.3877%	$ 4,463,606	FF1 207.99(g)	(1)
3	Dispatch Center Plant Held for Future Use	A.1.c				$ -	FF1 214	(1)
4	Dispatch Center Related Depreciation Reserve	A.1.d						
5	Dispatch Center Depreciation Reserve					$ 4,764,129	FF1 219.25(b) (part)	(1)
6	Transmission Related General Depreciation Reserve		$ 52,490,917	W&S	2.3877%	$ 1,253,326	FF1 219.28(b)	(1)
7	Total Dispatch Center Related Depreciation Reserve (line 5 6)					$ 6,017,455		
8	Dispatch Center Related Accumulated Deferred Taxes	A.1.e						
9	ADIT - Accelerated Amortization Property (Acct #281)		$ -	Plant	0.2333%	$ -	FF1 273.17(k)	(1)
10	ADIT - Other Property (Acct #282)		$ 1,143,462,163	Plant	0.2333%	$ 2,667,697	Line 27	(1)
11	ADIT - Other (Acct #283)					$ 2,876,873	Sheet 7, Line 30(d)	(1)
12	Less ADIT (Acct #190)					$ 581,682	Sheet 7, Line 12(d)	(1)
13	Total Dispatch Center Related ADIT (ine 9 10 11 - 12)					$ 4,962,888		
14	Other Regulatory Assets	A.1.f						
15	FAS 106		$ -	W&S	2.3877%	$ -	FF1 232.1	(1)
16	ASC 740 Regulatory Asset (FAS 109)		$ 87,768,732	Plant	0.2333%	$ 204,764	FF1 232.29(f)	(1)
17	Less ASC 740 Regulatory Liability (FAS 109)		$ 4,015,556	Plant	0.2333%	$ 9,368	FF1 278.1(f)	(1)
18	Total Other Regulatory Assets (line 15 16 - 17)		$ 83,753,176			$ 195,396		
19	Dispatch Center Prepayments	A.1.g	$ 105,048,059	W&S	2.3877%	$ 2,508,233	FF1 111.57(c)	(1)
20	Dispatch Center Materials and Supplies	A.1.h	$ 28,541,503	Plant	0.2333%	$ 66,587	FF1 227.8(c) + 5(c) fn	(1)
21	Dispatch Center Related Cash Working Capital	A.1.i						
22	Dispatch Center Operation and Maintenance Expense		$ 3,271,123	WC	12.50%	$ 408,890	Sheet 4, Line 14(f)	(1)
23	Dispatch Center Related Administrative and General Expense		$ 3,311,135	WC	12.50%	$ 413,892	Sheet 4, Line 26(f)	(2)
24	Total Dispatch Center Related Cash Working Capital (line 22 23)		$ 6,582,258			$ 822,782		
25	Account 282		$ 1,143,462,163	FF1 275.9(k)				
26	less amounts related to divestiture		$ -	FF1 275.4(k)				
27	Total Account 282 (line 25 26)		$ 1,143,462,163					

Notes:

Line	Description	Allocation Factor	Reference	Notes
28	Wages & Salary Allocation (W&S)	2.3877%	Sheet 6, Line 6(c)	(1)
29	Plant Allocation Allocation (Plant)	0.2333%	Sheet 6, Line 16(c)	(1)
30	Cash Working Capital (WC)	12.50%	OATT - Schedule 1, A.1.i	(1)

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.

(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated SCADA Revenue Requirement Under Changed Rates
Under Schedule 1, Appendix A
Expense Items For the Calendar year 2014
Sheet 4

	(a)	(b)	(c)	(d)	(e)	(f) (c) * (e)	(g)	(h)
Line	Description	Tariff Section	Total	Allocator	Allocation Factor	Dispatch Center Allocated	Reference	Notes
1	Dispatch Center Depreciation Expense	B						
2	Dispatch Center Plant Depreciation Expense					$ 276,720	See Line 31(d)	(1)
3	General Plant Depreciation Expense		$ 8,720,270	W&S	2.3877%	$ 208,214	FF1 336.10(b)	(1)
4	Total Dispatch Center Depreciation Expense (ine 2 3)					$ 484,934		
5	Dispatch Center Related Amortization of Investment Tax Credits	C	$ (1,310,106)	Plant	0.2333%	$ (3,056)	FF1 266.8(f) & 11(f)	(1)
6	Dispatch Center Related Municipal Tax Expense	D	$ 120,588,821	Plant	0.2333%	$ 281,334	FF1 263.5(i)	(1)
7	Dispatch Center Related Payroll Tax Expense	E	$ 12,412,619	W&S	2.3877%	$ 296,376	FF1 263.10(i)	(1)
8	Dispatch Center Operations & Maintenance Expense	F						
9	Load dispatching #561		$ -	Direct	100.0000%	$ -	FF1 321.84(b)	(1)
10	Load dispatching - Reliability #561.1		$ 1,389,220	Direct	100.0000%	$ 1,389,220	FF1 321.85(b)	(1)
11	Load dispatching - Mon & Oper Trans System 561.2		$ 1,311,222	Direct	100.0000%	$ 1,311,222	FF1 321.86(b)	(1)
12	Load dispatching - Trans Service & Scheduling #561.3		$ 570,681	Direct	100.0000%	$ 570,681	FF1 321.87(b)	(1)
13	Scheduling, System Control and Dispatch Services #561.4		$ 12,155,295		0%	$ -	FF1 321.88(b)	(1)
14	Total Dispatch Center O&M Expense (sum of lines [9-13])		$ 15,426,418			$ 3,271,123		
15	Dispatch Center Related Administrative & General Expenses	G						
16	Administrative and General Expenses		$ 145,329,829				FF1 323.197(b)	(1)
17	less Property Insurance (Acct #924)		$ 926,016				FF1 323.185(b)	(1)
18	less Regulatory Commission Expenses (Acct #928)		$ 9,560,209				FF1 323.189(b)	(1)
19	less General Advertising Expenses (Acct #930.1)		$ 32,018				FF1 323.191(b)	(1)
20	less Miscellaneous General Expenses (Acct #930.2) '(a)		$ 52,118				FF1 323.192(b) fn	(1)
21	less Merger-Related Costs		$ -					(2)
22	Subtotal (line 16 - sum of lines[17-21])		$ 134,759,468	W&S	2.3877%	$ 3,217,652		
23	Property Insurance		$ 926,016	Plant	0.2333%	$ 2,160	FF1 323.185(b)	(1)
24	FERC Assessments in Regulatory Commission Expenses (Acct #928)		$ 1,992,376	Plant	0.2333%	$ 4,648	FF1 350.7(d)	(1)
25	Transmission Merger-Related Costs		$ 10,517,524	T Plant	0.8241%	$ 86,675	Exhibit No. ES-201, Page 1 of 1, Ln.24 (H)	(2)
26	Total Dispatch Center Related A&G Expenses (sum of lines [22-25])		$ 148,195,384			$ 3,311,135		

NOTES:

Line	Description	Allocation Factor	Reference	Notes
27	Direct Allocation (Direct)	100.0000%		(1)
28	Wages & Salaries Allocation (W&S)	2.3877%	Sheet 6, Line 6(c)	(1)
29	Total Plant Allocation (Plant)	0.2333%	Sheet 6, Line 16(c)	(1)
30	Transmission Plant Allocation (T Plant)	0.8241%	Exhibit No. ES-216, Schedule 3, Page 6 of 6, Line 22(c)	(2)

Line	Description	Total Investment	Life Depr. Rate	Depreciation Expense	Reference	Notes
31	Mass. Ave. Service Center - 431 (Trans. Station Equipment)	$ 7,966,151	2.53%	$ 201,464	Sheet 6, Line 9(c)	(1)
32	SCADA Mass. Ave. - 421 (Trans. & Conversion Station Structures)	$ 2,816,142	2.19%	$ 61,646	Sheet 6, Line 10(c)	(1)
33	SCADA Mass. Ave. - 431 (Trans. Station Equipment)	$ 537,962	2.53%	$ 13,610	Sheet 6, Line 11(c)	(1)
34	Total	$ 11,320,255		$ 276,720	Sum Lines 31 thru 33	

(a) NSTAR Green Program costs are excludable for Transmission billing purposes. Reflects actual information per Eversource's accounting records.

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.

(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated SCADA Revenue Requirement Under Changed Rates
Under Schedule 1, Appendix A
Allocation Calculations For the Calendar year 2014
Sheet 6

	(a)	(b)	(c)		(d)	(e)
Line	Description	Tariff Section		Amount	Reference	Notes
1	Dispatch Center Wages & Salaries Allocation Factor	Definitions				
2	Direct Dispatch Center Wages & Salaries		$	2,858,118	Note (a)	(1)
3	NSTAR Electric Direct Wages & Salaries		$	152,023,518	FF1 354.28(b)	(1)
4	Less: Administrative & General Wages & Salaries		$	32,322,705	FF1 354.27(b)	(1)
5	Net NSTAR Electric Wages & Salaries (line 3 - 4)		$	119,700,813		
6	Wages & Salaries Allocation Factor (line 2 / 5)			2.3877%		
7	Dispatch Center Plant Allocation Factor	Definitions				
8	Investment In Dispatch Center Plant					
9	Mass. Ave. Service Center - 431 (Trans. Station Equipment)		$	7,966,151	Note (a)	(1)
10	SCADA Mass. Ave. - 421 (Trans. & Conversion Station Structures)		$	2,816,142		(1)
11	SCADA Mass. Ave. - 431 (Trans. Station Equipment)		$	537,962		(1)
12	Total Investment in Dispatch Center Plant (line 9 + 10 + 11)		$	11,320,255		
13	Dispatch Center Related General Plant		$	4,463,606	Sheet 3, Line 2(f)	(1)
14	Total Dispatch Center Plant Investment (line 12 + 13)		$	15,783,861		
15	Total Plant in Service		$	6,765,341,609	FF1 207.104(g)	(1)
16	Plant Allocation Factor (line 14 / 15)			0.2333%		
17	Dispatch Center Transmission Plant Allocation Factor	Definitions				(2)
18	Total Investment in Dispatch Center Plant (line 12)		$	11,320,255		
19	Dispatch Center Related General Plant (line 13)		$	4,463,606		
20	Total Dispatch Center Plant Investment (line 18 + 19)		$	15,783,861		
21	Total Investment in Transmission Plant		$	1,915,292,693	FF1 207.99(g)	
22	Dispatch Center Transmission Plant Allocation Factor (line 20 / 21)			0.8241%		(2)

Note (a): Reflects actual information per Eversource's accounting records.

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.

(2) The proposed revisions include the Dispatch Center Transmission Plant Allocation Factor

Exhibit No. ES-217
Schedule 1

Summary of Impact on Category A Revenue Requirements under Attachment ES-H, Schedule 21-ES to ISO-NE OATT (1-year amortization)

Eversource Energy Service Company

CL&P, PSNH, and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Comparison Under Present and Changed Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For the Calendar year 2016

Line	(A) Description	(B) Net Revenue Requirements under the Present Rates in Attachment ES-H	(C) Net Revenue Requirements under the Changed Rates in Attachment ES-H	(D) = (C) - (B) Difference	(E) = (D) / (B) % Difference
1	2016 Estimated Schedule ES-H Revenue Requirement	$ 58,607,159 (1)	$ 60,119,681 (2)	$ 1,513,000 (3)	2.58%

Notes
(1) Exhibit No. ES-217, Schedule 1, Page 2 of 2, Line 5(B)
(2) Exhibit No. ES-217, Schedule 1, Page 2 of 2, Line 5(C)
(3) In connection with the one-year amortization proposal (with the proposed effective date of June 1, 2016), Eversource is showing the revenue impact for the twelve-month period June 1, 2016 through May 31, 2017. Eversource is using revenue requirement calculations for the calendar year 2016 as an estimate for the twelve-month period beginning June 1, 2016. See Cooper Testimony Exhibit No. ES-200.

	2016	2017	Total
The amounts for each year are as follows:	$ 882,583	$ 630,416.67	$ 1,513,000

CL&P, PSNH, and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Comparison Under Present and Changed Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For the Calendar year 2016

Line	(A) Description		(B) Net Revenue Requirements under the Present Rates in Attachment ES-H			(C) Net Revenue Requirements under the Changed Rates in Attachment ES-H	
1	Total Schedule 21-ES Revenue Requirements	$	835,176,268	(2)	$	862,209,329	(3)
2	Regional Network Service (RNS) Revenue Credits	$	730,092,671	(4)	$	754,442,530	(5)
3	Localized Revenues Credits	$	34,370,344	(1)	$	35,541,024	(6)
4	Other Revenue Credits	$	12,106,094	(1)	$	12,106,094	(1)
5	Net Local Network Service Revenue Requirements *(Line 1 - 2 - 3 - 4)*	$	58,607,159		$	60,119,681	

Notes
(1) Support was filed as part of ES's Regulatory Oversight Filing with State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(2) Exhibit No. ES-217, Schedule 2, Page 1 of 7, Line 10(F)
(3) Exhibit No. ES-217, Schedule 3, Page 1 of 7, Line 10(F)

(4)

Line	Description		Amount		Reference
6	2014 RNS Revenue Credits	$	618,194,635		(1)
7	Plus: 2015 Forecasted Incremental Estimated PTF Revenue Credits		73,137,000		Exhibit No. ES-214, Schedule 2, Page 1 of 20, Line 4(f)
8	Plus: 2016 Forecasted Incremental Estimated PTF Revenue Credits		42,053,500		Exhibit No. ES-214, Schedule 2, Page 1 of 20, Line 9(f)
9	Less: 2015 Impact on RNS Revenue Credits due to 50 basis points		2,094,516		(a)
10	Less: 2016 Impact on RNS Revenue Credits due to 50 basis points		1,197,948		(a)
11	2016 RNS Revenue Credits under Current rates (Lines 6 + 7 + 8 - 9 - 10)	$	730,092,671	To Line 2(B)	

(5)

Line	Description		Amount		Reference
12	2016 RNS Revenue Credits under Present Rates	$	730,092,671		Line 2(B)
13	Plus: Incremental Estimated PTF Revenue Requirements		24,363,000		Exhibit No. ES-214, Schedule 1, Page 1 of 1, Line 1(D)
14	Less: Impact on RNS Revenue Credits due to 50 basis points		13,141		Exhibit No. ES-214, Schedule 3, Pages 8, 13 & 18 of 20, Lines 15(B) **Less** Exhibit No. ES-214, Schedule 2, Pages 8, 13 & 18 of 20, Lines 15(B)
15	2016 RNS Rev. Credits under Changed Rates (Lines 12 + 13 -14)	$	754,442,530	To Line 2(C)	

(6)

Line	Description		Amount		Reference
16	2016 Localized Revenue Credits under Present Rates	$	34,370,344		Line 3(B)
17	Plus: Incremental Estimated PTF Revenue Requirements		1,171,000		Exhibit No. ES-219, Schedule 1, Page 1 of 1, Line 1(D)
18	Less: Impact on Localized Revenue Credits due to 50 basis points		320		Exhibit No. ES-219, Schedule 3, Pages 5, 10, 15, 20, and 25 of 26, Lines 15(B) **Less** Exhibit No. ES-219, Schedule 3, Pages 5, 10, 15, 20, and 25 of 26, Lines 15(B)
19	2016 Localized Rev. Credits under Changed Rates (Lines 16+17-18)	$	35,541,024	To Line 3(C)	

(a)

Line	Description		2015	All References below come from Exhibit No. ES-214 Schedule 2		2016	All References below come from Exhibit No. ES-214 Schedule 2
20	CL&P PTF Plant Additions	$	276,000,000	Page 1 of 20, Line 2(C)	$	68,000,000	Page 1 of 20, Line 7(C)
21	CL&P Cost of Capital Rate for 50bp Incentive		0.4396%	Page 8 of 20, Line 12(B)		0.4396%	Page 8 of 20, Line 12(B)
22	CL&P Subtotal (Lines 20 x 21)	$	1,213,296		$	298,928	
23	PSNH PTF Plant Additions	$	114,000,000	Page 1 of 20, Line 2(D)	$	117,000,000	Page 1 of 20, Line 7(D)
24	PSNH Cost of Capital Rate for 50bp Incentive		0.4540%	Page 13 of 20, Line 12(B)		0.4540%	Page 13 of 20, Line 12(B)
25	PSNH Subtotal (Lines 23 x 24)	$	517,560		$	531,180	
26	WMECO PTF Plant Additions	$	87,000,000	Page 1 of 20, Line 2(E)	$	88,000,000	Page 1 of 20, Line 7(E)
27	WMECO Cost of Capital Rate for 50bp Incentive		0.4180%	Page 18 of 20, Line 12(B)		0.4180%	Page 18 of 20, Line 12(B)
28	WMECO Subtotal (Lines 26 x 27)	$	363,660		$	367,840	
29	**Total** (Lines 22 + 25 +28)	$	2,094,516	To Line 9(B)	$	1,197,948	To Line 10(B)

Exhibit No. ES-217
Schedule 2

Category A Revenue Requirements under the Present Rates

Eversource Energy Service Company

CL&P, PSNH, and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Under Present Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For the Calendar year 2016

	(A)	(B)		(C)		(D)		(E)		(F)=(C)+(D)+(E)
Line	**Description**	**Reference**		**CL&P**		**PSNH**		**WMECO**		**Total**
1	2014 Actual Schedule 21-ES, Category A Revenue Requirement		$	477,229,327 (1)	$	112,110,056 (2)	$	116,984,685 (3)	$	706,324,068
2	Estimated 2015 Schedule 21-ES, Category A Plant Additions	(4) Exh bit No. ES-217, Schedule 2, Page 2 of 7,	$	278,000,000	$	123,000,000	$	100,000,000	$	501,000,000
3	Carrying Charge Factor (CCF)	Note (c)		15.70%		17.29%		14.16%		15.78%
4	2015 Incremental Estimated Schedule 21-ES, Category A Revenue Requirement	Line 2 x 3		43,646,000		21,266,700		14,160,000		79,072,700
5	2015 Incremental Estimated Schedule 21-ES, Category A CWIP Revenue Requirements	(4)	$	6,218,000	$	-	$	(999,000)	$	5,219,000
6	Total Estimated Schedule 21-ES, Category A Revenue Requirement for 2015	Line 1 + 4 + 5	$	527,093,327	$	133,376,756	$	130,145,685	$	790,615,768
7	Estimated 2016 Schedule 21-ES, Category A Plant Additions	(4)	$	72,000,000	$	117,000,000	$	92,000,000	$	281,000,000
8	Carrying Charge Factor (CCF)	Line 3		15.70%		17.29%		14.16%		15.86%
9	2016 Incremental Estimated Schedule 21-ES, Category A Revenue Requirement	Line 7 x 8		11,304,000		20,229,300		13,027,200		44,560,500
10	Total Estimated Schedule 21-ES, Category A Revenue Requirement for 2016	Line 6 + 9 + 10	$	538,397,327	$	153,606,056	$	143,172,885	$	835,176,268

Notes:
(1) Exhibit No. ES-217, Schedule 2, Page 2 of 7, Line 29(C)
(2) Exhibit No. ES-217, Schedule 2, Page 2 of 7, Line 29(D)
(3) Exhibit No. ES-217, Schedule 2, Page 2 of 7, Line 29(E)
(4) Based on Eversource's Forecast

CL&P, PSNH, and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Comparison Under Present Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For Costs in 2014
Sheet 2a

Line	(A)	(B) Attachment H Reference Section:	(C) CL&P	(D) PSNH	(E) WMECO	(F) Total	(G) Source	Notes
	I. INVESTMENT BASE							
1	Transmission Plant	II(A)(1)(a)	2,977,569,726	648,561,975	829,609,658	4,455,741,359	Sheet 3	(a)
2	General Plant	II(A)(1)(b)	86,941,769	58,369,540	18,348,753	163,660,062	Sheet 3	(a)
3	Plant Held For Future Use	II(A)(1)(c)	35,612,990	13,626,119	750,000	49,989,109	Sheet 3	(a)
4	Total Plant (Lines 1+2+3)		3,100,124,485	720,557,634	848,708,411	4,669,390,530		
5	Accumulated Depreciation	II(A)(1)(e)	603,780,016	132,512,720	51,920,388	788,213,124	Sheet 3	(a)
6	Accumulated Deferred Income Taxes	II(A)(1)(f)	391,238,076	123,116,055	201,101,631	715,455,762	Sheet 3	(a)
7	Loss On Reacquired Debt	II(A)(1)(g)	5,711,371	2,107,937	355,953	8,175,261	Sheet 3	(a)
8	Other Regulatory Assets	II(A)(1)(h)	18,536,117	8,385,129	6,105,712	33,026,958	Sheet 3	(b)
9	Net Investment (Line 4-5-6+7+8)		2,129,353,881	475,421,925	602,148,057	3,206,923,863		(b)
10	Prepayments	II(A)(1)(j)	19,487,085	4,911,873	642,737	25,041,695	Sheet 3	(a)
11	Materials & Supplies	II(A)(1)(k)	36,123,136	10,822,161	3,067,304	50,012,601	Sheet 3	(a)
12	Cash Working Capital	II(A)(1)(l)	9,104,674	2,502,459	1,752,501	13,359,634	Sheet 3	(b)
13	Sub Total (Line 10+11+12)		64,714,895	18,236,493	5,462,542	88,413,930		
14	Total Investment Base Excluding CWIP (Lines 9+13)		2,194,068,776	493,658,418	607,610,599	3,295,337,793		(b)
15	Construction Work in Progress (13 mo. Average)	II(A)(1)(d)	134,757,788	-	4,772,177	139,529,965	Sheet 3	(a)
16	AFUDC Regulatory Liability (13 mo. Average)	II(A)(1)(i)	54,157,503	-	9,213,804	63,371,307	Sheet 3	(a)
17	Total Investment Base Including CWIP (Lines 14+15-16)		2,274,669,061	493,658,418	603,168,972	3,371,496,451		(a)
	II. REVENUE REQUIREMENTS							
18	Investment Return and Income Taxes - at 10.57% ROE	II(A)	263,101,757	56,577,698	67,261,278	386,940,733	Sheet 4a, Sheet 5a , Sheet 6a	(b)
19	Investment Return and Income Taxes - CWIP - at 10.57% ROE	II(A)	9,665,183	-	(491,679)	9,173,504	Sheet 4a, Sheet 5a , Sheet 6a	(b)
20	Depreciation Expense	II(B)	72,297,134	15,519,668	16,577,959	104,394,761	Sheet 7	(a)
21	Amortization of Loss on Reacquired Debt	II(C)	593,685	246,881	49,668	890,234	Sheet 7	(a)
22	Investment Tax Credit	II(D)	(428,304)	(4,852)	(35,604)	(468,760)	Sheet 7	(a)
23	Property Tax Expense	II(E)	45,144,822	18,087,310	18,717,332	81,949,464	Sheet 7	(a)
24	Payroll Tax Expense	II(F)	322,527	(4,083)	18,291	336,735	Sheet 7	(a)
25	Operation & Maintenance Expense	II(G)	37,849,988	10,282,288	6,368,294	54,500,570	Sheet 7	(a)
26	Administrative & General Expense	II(H)	37,202,294	10,348,117	8,041,502	55,591,913	Sheet 7	(b)
27	Transmission Support Expenses	II(I)	1,625,568	898,916	457,017	2,981,501	Sheet 8	(a)
28	Transmission Related Taxes and Fees Charge	II(J)	9,854,673	158,113	20,627	10,033,413	Note 1	(a)
29	Total Revenue Requirements (Line 18 thru 28)		477,229,327	112,110,056	116,984,685	706,324,068		(b)

Note 1 - Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment B.

Notes

(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
Provided this support because these balances will be revised under the changed rates.
(c) Carrying Charge Factor ([Line 29 - Line 19] / Line 1) 15.70% 17 29% 14.16%

CL&P, PSNH, and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Comparison Under Present Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For Costs in 2014
Sheet 3

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				FF1		FF1		FF1	
Line	Description	FF1 Reference	CL&P	Line	PSNH	Line	WMECO	Line	Notes
	Transmission Plant								
1	Transmission Plant		2,977,602,438	Sheet 9	648,561,975	Sheet 11	829,609,658	Sheet 13	(a)
2	CL&P Dispatch Center	Note 1	32,712		-		-		(a)
3	Net Transmission Plant (line 1-2)		2,977,569,726		648,561,975		829,609,658		
	General Plant								
4	General Plant	FF1 page 204 footnote	102,812,641	Line 99	58,369,540	Line 99	18,348,753	Line 99	(a)
5	CL&P General Dispatch Center	Note 1	15,870,872		-		-		(a)
6	Net General Plant (line 4-5)		86,941,769		58,369,540		18,348,753		
7	Transmission Plant Held for Future Use		35,612,990	Sheet 9	13,626,119	Sheet 11	750,000	Sheet 13	
	Transmission Accumulated Depreciation								
8	Transmission Accum. Depreciation	FF1 page 219	579,929,318	Line 25	117,852,509	Line 25	47,948,646	Line 25	(a)
9	CL&P Dispatch Center Accum. Depreciation	Note 1	(1,482,625)		-		-		(a)
10	Transmission Related General Plant Accum.Depreciation	FF1 page 219	26,085,325	Line 28	14,660,211	Line 28	3,971,742	Line 28	(a)
11	CL&P Dispatch Center General Accum. Depreciation	Note 1	3,717,252		-		-		(a)
12	Net Accumulated Depreciation (line 8-9 10-11)		603,780,016		132,512,720		51,920,388		
	Transmission Accumulated Deferred Taxes								
13	Accumulated Deferred Taxes (281 to 283)	FF1 page 274 & 276 footnote	451,817,902	Line 9 & Line 19	134,008,391	Line 9 & Line 19	213,650,889	Line 9 & Line 19	(a)
14	Accumulated Deferred Taxes (190)	FF1 page 234 footnote	59,128,935	Line 18	10,892,336	Line 18	12,549,258	Line 18	(a)
15	Reserve for Disputed Transactions	FF1 page 234 footnote	2,134,971	Line 18	-	Line 18	-	Line 18	(a)
16	CL&P Dispatch Center ADIT ("T" and General)	Note 1	3,585,862		-		-		(a)
17	Total (line 13-14 15-16)		391,238,076		123,116,055		201,101,631		
18	Unam. Loss on Reacquired Debt (189)	FF1 page 110 footnote	5,711,371	Line 81	2,107,937	Line 81	355,953	Line 81	(a)
	Other Regulatory Assets								
19	FAS 106 (FASB ASC 960/962)	FF1 page 232, 232.1, 232.1 footnote	(9,267)	Line 27	282,181	Line 15	3,119	Line 1	(a)
20	FAS 109 (FASB ASC 740)	FF1 page 232, 232.1, 232.1 footnote	22,783,548	Line 7	8,112,367	Line 1	6,178,066	Line 9	(a)
21	Other Regulatory Liabilities	FF1 page 278 footnote	4,238,164	Line 3	9,419	Line 1	75,473	Line 5	(a)
22	Total (line 19 20-21)		18,536,117		8,385,129		6,105,712		
23	Transmission Prepayments (165)	FF1 page 110 Footnote	19,487,085	Line 57	4,911,873	Line 57	642,737	Line 57	(a)
24	Transmission Materials and Supplies	FF1 page 227 Footnote	36,123,136	Line 8	10,822,161	Line 8	3,067,304	Line 8	(a)
	Cash Working Capital								
25	Operation & Maintenance Expense	Sheet 7	37,849,988		10,282,288		6,368,294		(a)
26	Administrative & General Expense	Sheet 7	37,202,294		10,348,117		8,041,502		(b)
27	Subtotal (line 25 26)		75,052,282		20,630,405		14,409,796		(a)
28	x 45 days/360 days	Section II.A.1(I) of Attachment NU-H	0.125		0.125		0.125		(a)
29	Total current Year End (line 27*28)		9,381,535		2,578,801		1,801,225		(a)
30	Prior Year End Cash Working Capital	Note 1	8,827,812		2,426,116		1,703,777		(a)
31	Average Cash Working Capital [(line 29 30)/2]		9,104,674		2,502,459		1,752,501		(a)
32	Construction Work in Progress (13 mo. avg.)	**Attachment A1**	134,757,788		-		4,772,177		(a)
33	AFUDC Regulatory Liability (13 mo. avg.)	**Attachment A1**	54,157,503		-		9,213,804		(a)

Note 1 - Reflects actual information per the Company's accounting records.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
Provided this support because these balances will be revised under the changed rates.

The Connecticut Light & Power Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Under Present Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For Costs in 2014
Sheet 4a

	(A)	(B) YEAR END CAPITALIZATION		(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL		(E) = (C) x (D) WEIGHTED COST OF CAPITAL	(F) = (E) Equity Only EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 2,579,060,322	Note 2	45.78%	5.36%	Note 2	2.45%		
2	PREFERRED STOCK	$ 116,868,097	Note 2	2.07%	4.80%	Note 2	0.10%	0.10%	
3	COMMON EQUITY	$ 2,938,441,767	Note 2	52.15%	10.57%	Note 1	5.51%	5.51%	
4	TOTAL	$ 5,634,370,186		100.00%			8.06%	5.61%	

Cost of Capital Rate=

5	(a) Weighted Cost of Capital	=	8.06%									
	(b) Federal Income Tax	= ((	R.O.E.	+ (	Total Inv. (Tax Credit)	+	Eq. AFUDC of Deprec. Exp.	) /	Total Inv. Base	) *	Federal Income Tax Rate	)
				(	1	-	Federal Income Tax Rate	)				
	Source		Line 4, Col. (F)		Sheet 7		FF1 page 336 ln. 7b + 10b footnotes		For Costs in 2014		Federal Corporate Tax Rate	
6		= ((	5.61%	+ (	(428,304)	+	2,307,409	) /	2,274,669,061	) *	35.00%	)
7				(	1	-	35.00%	)				
							Federal Corporate Tax Rate					
8		=	3.0653%									

	(c) State Income Tax	= ((	R.O.E.	+ (	Total Inv. (Tax Credit)	+	Eq. AFUDC of Deprec. Exp.	) /	Total Inv. Base	) +	Federal Income Tax	) * (	State Income Tax Rate	)
				(	1	-	State Income Tax Rate	)						
	Source		Line 4, Col. (F)		Sheet 7		FF1 page 336 ln. 7b + 10b footnotes		For Costs in 2014		Line 8, Col. (B)		Connecticut Corporate Tax Rate	
9		= ((	5.61%	+ (	(428,304)	+	2,307,409	) /	2,274,669,061	) +	3.0653%	) * (	9.00%	)
10				(	1	-	9.00%	)						
							Connecticut Corporate Tax Rate							
11		=	0.8662%											
12	(a)+(b)+(c) Cost of Capital Rate	=	11.9915%											

		Total Transmission	-	CWIP	=	Total T - Excluding CWIP	Reference
13	INVESTMENT BASE	$2,274,669,061		$80,600,285		$2,194,068,776	For Costs in 2014
14	x Cost of Capital Rate	11.9915%		11.9915%		11.9915%	Line 12
15	= Investment Return and Income Taxes	$272,766,940		$9,665,183		$263,101,757	

Note 1 - ROE per FERC Order in Docket No. ER04-157 dated March 24, 2008.
Note 2 - Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Provided this support because the balance in "Total Inv. Base" will be revised under the Changed Rates

Public Service Company of New Hampshire
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Under Present Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For Costs in 2014
Sheet 5a

	(A)	(B) YEAR END CAPITALIZATION		(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL		(E) = (C) x (D) WEIGHTED COST OF CAPITAL	(F) = (E) Equity Only EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 1,070,020,120	Note 2	46.56%	4.15%	Note 2	1.93%		
2	PREFERRED STOCK	$ -	Note 2	0.00%	0.00%	Note 2	0.00%	0.00%	
3	COMMON EQUITY	$ 1,228,095,985	Note 2	53.44%	10.57%	Note 1	5.65%	5.65%	
4	TOTAL	$ 2,298,116,105		100.00%			7.58%	5.65%	

Cost of Capital Rate=

5	(a) Weighted Cost of Capital	=	7.58%

(b) Federal Income Tax = ((R.O.E. + (Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate)) / Total Inv. Base) * Federal Income Tax Rate)

	Source				FF1 page 336 ln. 7b + 10b		For Costs in 2014		Federal Corporate Tax Rate
				Sheet 7	footnotes				
6	= ((	5.65%	+ (	(4,852)	+ 230,083	) /	493,658,418	) *	35.00%)
7			(	1	- 35.00%	)			
					Federal Corporate Tax Rate				
8	=	3.0669%							

(c) State Income Tax = ((R.O.E. + (Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate)) / Total Inv. Base) + Federal Income Tax) * (State Income Tax Rate)

	Source				FF1 page 336 ln. 7b + 10b		For Costs in 2014				New Hampshire Corporate Tax Rate
				Sheet 7	footnotes						
9	= ((	5.65%	+ (	(4,852)	+ 230,083	) /	493,658,418	) +	3.0669%	) * (	8.50%)
10			(	1	- 8.50%	)					
					New Hampshire Corporate Tax Rate						
11	=	0.8140%									

12	(a)+(b)+(c) Cost of Capital Rate	=	11.4609%

		Total Transmission	- CWIP	= Total T - Excluding CWIP	Reference
13	INVESTMENT BASE	$493,658,418	-	$493,658,418	For Costs in 2014
14	x Cost of Capital Rate	11.4609%	11.4609%	11.4609%	Line 12
15	= Investment Return and Income Taxes	$56,577,698	-	$56,577,698	

Note 1 - ROE per FERC Order in Docket No. ER04-157 dated March 24, 2008.
Note 2 - Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Provided this support because the balance in "Total Inv. Base" will be revised under the Changed Rates

Western Massachusetts Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Under Present Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For Costs in 2014
Sheet 6a

	(A)	(B) YEAR END CAPITALIZATION		(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL		(E) = (C) x (D) WEIGHTED COST OF CAPITAL	(F) = (E) Equity Only EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 567,833,428	Note 2	49.55%	4.31%	Note 2	2.14%		
2	PREFERRED STOCK	$ -	Note 2	0.00%	0.00%	Note 2	0.00%	0.00%	
3	COMMON EQUITY	$ 578,162,814	Note 2	50.45%	10.57%	Note 1	5.33%	5.33%	
4	TOTAL	$ 1,145,996,242		100.00%			7.47%	5.33%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 7.47%

(b) Federal Income Tax = ((R.O.E. + (Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / Total Inv. Base) * Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

Source: Sheet 7; FF1 page 336 ln. 7b + 10b footnotes; For Costs in 2014; Federal Corporate Tax Rate

6 = ((5.33% + ((35,604) + 186,099) / 603,168,972) * 35.00%)
7 (1 - 35.00%) (Federal Corporate Tax Rate)

8 = 2.8834%

(c) State Income Tax = ((R.O.E. + (Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / Total Inv. Base) + Federal Income Tax) * (State Income Tax Rate) / (1 - State Income Tax Rate)

Source: Sheet 7; FF1 page 336 ln. 7b + 10b footnotes; For Costs in 2014; Massachusetts Corporate Tax Rate

9 = ((5.33% + ((35,604) + 186,099) / 603,168,972) + 2.8834%) * (8.00%)
10 (1 - 8.00%) (Massachusetts Corporate Tax Rate)

11 = 0.7164%

12 (a)+(b)+(c) Cost of Capital Rate = 11.0698%

		Total Transmission	- CWIP	= Total T - Excluding CWIP	Reference
13	INVESTMENT BASE	$603,168,972	($4,441,627)	$607,610,599	For Costs in 2014
14	x Cost of Capital Rate	11.0698%	11.0698%	11.0698%	Line 12
15	= Investment Return and Income Taxes	$66,769,599	($491,679)	$67,261,278	

Note 1 - ROE per FERC Order in Docket No. ER04-157 dated March 24, 2008.
Note 2 - Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes

(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Provided this support because the balance in "Total Inv. Base" will be revised under the Changed Rates

CL&P, PSNH, and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Comparison Under Present Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For Costs in 2014
Sheet 7

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line	Description	FF1 Reference	CL&P Year End	FF1 Line	PSNH Year End	FF1 Line	WMECO Year End	FF1 Line	Notes
	Depreciation Expense								
1	Transmission Depreciation	FF1 page 336	69,626,166	7b	12,792,512	7b	15,972,687	7b	(a)
2	General Depreciation	FF1 page 336 footnote	4,980,574	10b	2,727,156	10b	789,658	10b	(a)
3	AFUDC Regulatory Credit	Attachment A1	1,145,364		-		184,386		(a)
4	Dispatch Plant Depreciation ("T" and General)	Note 1	1,164,242		-		-		(a)
5	Net Depreciation Expense (line 1+2-3-4)		72,297,134		15,519,668		16,577,959		
6	Amortization of Loss on Reacquired Debt	FF1 page 114 footnote	593,685	64c	246,881	64c	49,668	64c	(a)
	Investment Tax Credits								
7	Amortization of Investment Tax Credits	FF1 page 266 footnote	(428,304)	8f	(4,852)	8f	(35,604)	8f	(a)
8	Dispatch Center ITC ("T" and General)	Note 1	-		-		-		(a)
9	Net Investment Tax Credit (line 7-8)		(428,304)		(4,852)		(35,604)		
	Property Taxes								
10	Transmission Property Taxes	FF1 page 262 footnote	45,370,701	25i	18,087,310	Note 3	18,717,332	32i	(a)
11	General Property Taxes (included in line 10)	Note 2	-		-		-		(a)
12	Dispatch Center Property Taxes ("T" and General)	Note 1	225,879		-		-		(a)
13	Net Property Taxes (line 10+11-12)		45,144,822		18,087,310		18,717,332		
	Payroll Taxes:								
14	Federal Unemployment	FF1 page 262 footnote	5,226	3i	(51)	2i	283	3i	(a)
15	FICA	FF1 page 262 footnote	233,351	5i	(3,062)	4i	13,202	5i	(a)
16	Medicare	FF1 page 262 footnote	65,613	9i	(816)	7i	3,757	9i	(a)
17	CT Unemployment	FF1 page 262, 262.1, 262 footnote	16,786	15i	(128)	7i	852	13i	(a)
18	DC Unemployment	FF1 page 262.1 footnote	11	14i	-		1	6i	(a)
19	FL Unemployment	FF1 page 262.1 footnote	1	18i	-	27i	-	10i	(a)
20	MI Unemployment	FF1 page 262.1 footnote	6	22i	-	31i	-	14i	(a)
21	MA Unemployment	FF1 page 262, 262.1, 262 footnote	(285)	32i	2	15i	69	22i	(a)
22	MA Universal Health	FF1 page 262, 262.1, 262 footnote	64	33i	(1)	16i	19	27i	(a)
23	NH Unemployment	FF1 page 262.1, 262, 262 footnote	1,754	4i	(27)	14i	108	37i	(a)
24	NJ Unemployment	FF1 page 262 footnote	-		-		-		(a)
25	NY Unemployment	FF1 page 262.1 footnote	-	10i	-		-		(a)
26	Total Payroll Tax Exp (sum of line 14 through 25)		322,527		(4,083)		18,291		
	Transmission Operation and Maintenance								
27	Operation and Maintenance	FF1 page 321	77,432,007	112	51,082,852	112	20,725,279	112	(a)
28	Transmission of Electricity by Others - #565	FF1 page 321	21,727,966	96	37,174,569	96	13,174,678	96	(a)
29		FF1 page 321		84		84		84	(a)
30	Account 561.1	FF1 page 321	3,245,594	85	653,575	85	12,368	85	(a)
31	Account 561 2	FF1 page 321	5,212,556	86	474,690	86	50,569	86	(a)
32	Account 561 3	FF1 page 321	2,238,612	87	36,962	87	13,262	87	(a)
33	Account 561.4	FF1 page 321	7,157,291	88	2,460,768	88	1,106,108	88	(a)
34	Station Expenses & Rents - #562 / #567	FF1 page 321	-	93+98	-	93+98	-	93+98	(a)
35	Net O&M (line 27 - [sum lines 28 through 34])		37,849,988		10,282,288		6,368,294		
	Transmission Administrative and General								
36	Administrative and General	FF1 page 320 footnote	37,202,294	197	10,348,117	197	8,041,502	197	(a)
37	Public Education Expenses	FF1 page 114 footnote	-	49	-	49	-	49	(a)
38	Total Administrative and General (line 36+37)		37,202,294		10,348,117		8,041,502		(b)

Note 1 - Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.
Note 2 - Reflects actual information per Eversource's accounting records.
Note 3 -This includes local New Hampshire, Vermont, and Maine property taxes (Page 262 ln, 23i, footnote + Page 262 ln, 30i, footnote + Page 262.1 ln, 2i, footnote).

Notes

(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
Provided this support because these balances will be revised under the changed rates.

Exhibit No. ES-217
Schedule 3

Category A Revenue Requirements under the Changed Rates

Eversource Energy Service Company

CL&P, PSNH, and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Under Changed Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For the Calendar year 2016

	(A)	(B)	(C)	(D)	(E)	(F)=(C)+(D)+(E)
Line	**Description**	**Reference**	**CL&P**	**PSNH**	**WMECO**	**Total**
1	2014 Actual Schedule 21-ES, Category A Revenue Requirement		$ 495,370,614 (1)	$ 116,212,860 (2)	$ 121,773,655 (3)	$ 733,357,129
2	Estimated 2015 Schedule 21-ES, Category A Plant Additions	(4)	$ 278,000,000	$ 123,000,000	$ 100,000,000	$ 501,000,000
3	Carrying Charge Factor (CCF)	Exhibit No. ES-217, Schedule 2, Page 2 of 7, Note (c)	15.70%	17.29%	14.16%	15.78%
4	2015 Incremental Estimated Schedule 21-ES, Category A Revenue Requirement	Line 2 x 3	43,646,000	21,266,700	14,160,000	79,072,700
5	2015 Incremental Estimated Schedule 21-ES, Category A CWIP Revenue Requirements	(4)	$ 6,218,000	$ -	$ (999,000)	$ 5,219,000
6	Total Estimated Schedule 21-ES, Category A Revenue Requirement for 2015	Line 1 + 4 + 5	$ 545,234,614	$ 137,479,560	$ 134,934,655	$ 817,648,829
7	Estimated 2016 Schedule 21-ES, Category A Plant Additions	(4)	$ 72,000,000	$ 117,000,000	$ 92,000,000	$ 281,000,000
8	Carrying Charge Factor (CCF)	Line 3	15.70%	17.29%	14.16%	15.86%
9	2016 Incremental Estimated Schedule 21-ES, Category A Revenue Requirement	Line 7 x 8	11,304,000	20,229,300	13,027,200	44,560,500
10	Total Estimated Schedule 21-ES, Category A Revenue Requirement for 2016	Line 6 + 9 + 10	$ 556,538,614	$ 157,708,860	$ 147,961,855	$ 862,209,329

Notes:
(1) Exhibit No. ES-217, Schedule 3, Page 2 of 7, Line 29(C)
(2) Exhibit No. ES-217, Schedule 3, Page 2 of 7, Line 29(D)
(3) Exhibit No. ES-217, Schedule 3, Page 2 of 7, Line 29(E)
(4) Based on Eversource's Forecast

CL&P, PSNH, and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Under Changed Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For Costs in 2014
Sheet 2a

Line	(A)	(B) Attachment H Reference Section:	(C) CL&P	(D) PSNH	(E) WMECO	(F) Total	(G) Source	Notes
	I. INVESTMENT BASE							
1	Transmission Plant	II(A)(1)(a)	2,977,569,726	648,561,975	829,609,658	4,455,741,359	Sheet 3	(a)
2	General Plant	II(A)(1)(b)	86,941,769	58,369,540	18,348,753	163,660,062	Sheet 3	(a)
3	Plant Held For Future Use	II(A)(1)(c)	35,612,990	13,626,119	750,000	49,989,109	Sheet 3	(a)
4	Total Plant (Lines 1+2+3)		3,100,124,485	720,557,634	848,708,411	4,669,390,530		
5	Accumulated Depreciation	II(A)(1)(e)	603,780,016	132,512,720	51,920,388	788,213,124	Sheet 3	(a)
6	Accumulated Deferred Income Taxes	II(A)(1)(f)	391,238,076	123,116,055	201,101,631	715,455,762	Sheet 3	(a)
7	Loss On Reacquired Debt	II(A)(1)(g)	5,711,371	2,107,937	355,953	8,175,261	Sheet 3	(a)
8	Other Regulatory Assets	II(A)(1)(h)	18,536,117	8,385,129	6,105,712	33,026,958	Sheet 3	(b)
9	Net Investment (Line 4-5-6+7+8)		2,129,353,881	475,421,925	602,148,057	3,206,923,863		(b)
10	Prepayments	II(A)(1)(j)	19,487,085	4,911,873	642,737	25,041,695	Sheet 3	(a)
11	Materials & Supplies	II(A)(1)(k)	36,123,136	10,822,161	3,067,304	50,012,601	Sheet 3	(a)
12	Cash Working Capital	II(A)(1)(l)	10,230,211	2,757,060	2,049,755	15,037,026	Sheet 3	(b)
13	Sub Total (Line 10+11+12)		65,840,432	18,491,094	5,759,796	90,091,322		
14	Total Investment Base Excluding CWIP (Lines 9+13)		2,195,194,313	493,913,019	607,907,853	3,297,015,185		
15	Construction Work in Progress (13 mo. Average)	II(A)(1)(d)	134,757,788	-	4,772,177	139,529,965	Sheet 3	(a)
16	AFUDC Regulatory Liability (13 mo. Average)	II(A)(1)(i)	54,157,503	-	9,213,804	63,371,307	Sheet 3	(a)
17	Total Investment Base Including CWIP (Lines 14+15-16)		2,275,794,598	493,913,019	603,466,226	3,373,173,843		
	II. REVENUE REQUIREMENTS							
18	Investment Return and Income Taxes - at 10.57% ROE	II(A)	263,234,531	56,606,877	67,294,184	387,135,592	Sheet 4a, Sheet 5a , Sheet 6a	(b)
19	Investment Return and Income Taxes - CWIP - at 10.57% ROE	II(A)	9,665,103	-	(491,679)	9,173,424	Sheet 4a, Sheet 5a , Sheet 6a	(b)
20	Depreciation Expense	II(B)	72,297,134	15,519,668	16,577,959	104,394,761	Sheet 7	(a)
21	Amortization of Loss on Reacquired Debt	II(C)	593,685	246,881	49,668	890,234	Sheet 7	(a)
22	Investment Tax Credit	II(D)	(428,304)	(4,852)	(35,604)	(468,760)	Sheet 7	(a)
23	Property Tax Expense	II(E)	45,144,822	18,087,310	18,717,332	81,949,464	Sheet 7	(a)
24	Payroll Tax Expense	II(F)	322,527	(4,083)	18,291	336,735	Sheet 7	(a)
25	Operation & Maintenance Expense	II(G)	37,849,988	10,282,288	6,368,294	54,500,570	Sheet 7	(a)
26	Administrative & General Expense	II(H)	55,210,887	14,421,742	12,797,566	82,430,195	Sheet 7	(b)
27	Transmission Support Expenses	II(I)	1,625,568	898,916	457,017	2,981,501	Sheet 8	(a)
28	Transmission Related Taxes and Fees Charge	II(J)	9,854,673	158,113	20,627	10,033,413	Note 1	(a)
29	Total Revenue Requirements (Line 18 thru 28)		495,370,614	116,212,860	121,773,655	733,357,129		(b)

Note 1 - Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment B.

Notes

(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247

(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

CL&P, PSNH, and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Under Changed Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For Costs in 2014
Sheet 3

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	
				FF1		FF1		FF1	
Line	Description	FF1 Reference	CL&P	Line	PSNH	Line	WMECO	Line	Notes
	Transmission Plant								
1	Transmission Plant		2,977,602,438	Sheet 9	648,561,975	Sheet 11	829,609,658	Sheet 13	(a)
2	CL&P Dispatch Center	Note 1	32,712		-		-		(a)
3	Net Transmission Plant (line 1-2)		2,977,569,726		648,561,975		829,609,658		
	General Plant								
4	General Plant	FF1 page 204 footnote	102,812,641	Line 99	58,369,540	Line 99	18,348,753	Line 99	(a)
5	CL&P General Dispatch Center	Note 1	15,870,872		-		-		(a)
6	Net General Plant (line 4-5)		86,941,769		58,369,540		18,348,753		
7	Transmission Plant Held for Future Use		35,612,990	Sheet 9	13,626,119	Sheet 11	750,000	Sheet 13	
	Transmission Accumulated Depreciation								
8	Transmission Accum. Depreciation	FF1 page 219	579,929,318	Line 25	117,852,509	Line 25	47,948,646	Line 25	(a)
9	CL&P Dispatch Center Accum. Depreciation	Note 1	(1,482,625)		-		-		(a)
10	Transmission Related General Plant Accum.Depreciation	FF1 page 219	26,085,325	Line 28	14,660,211	Line 28	3,971,742	Line 28	(a)
11	CL&P Dispatch Center General Accum. Depreciation	Note 1	3,717,252		-		-		(a)
12	Net Accumulated Depreciation (line 8-9 10-11)		603,780,016		132,512,720		51,920,388		
	Transmission Accumulated Deferred Taxes								
13	Accumulated Deferred Taxes (281 to 283)	FF1 page 274 & 276 footnote	451,817,902	Line 9 & Line 19	134,008,391	Line 9 & Line 19	213,650,889	Line 9 & Line 19	(a)
14	Accumulated Deferred Taxes (190)	FF1 page 234 footnote	59,128,935	Line 18	10,892,336	Line 18	12,549,258	Line 18	(a)
15	Reserve for Disputed Transactions	FF1 page 234 footnote	2,134,971	Line 18	-	Line 18	-	Line 18	(a)
16	CL&P Dispatch Center ADIT ("T" and General)	Note 1	3,585,862		-		-		(a)
17	Total (line 13-14 15-16)		391,238,076		123,116,055		201,101,631		
18	Unam. Loss on Reacquired Debt (189)	FF1 page 110 footnote	5,711,371	Line 81	2,107,937	Line 81	355,953	Line 81	(a)
	Other Regulatory Assets								
19	FAS 106 (FASB ASC 960/962)	FF1 page 232, 232.1, 232.1 footnote	(9,267)	Line 27	282,181	Line 15	3,119	Line 1	(a)
20	FAS 109 (FASB ASC 740)	FF1 page 232, 232.1, 232.1 footnote	22,783,548	Line 7	8,112,367	Line 1	6,178,066	Line 9	(a)
21	Other Regulatory Liabilities	FF1 page 278 footnote	4,238,164	Line 3	9,419	Line 1	75,473	Line 5	(a)
22	Total (line 19 20-21)		18,536,117		8,385,129		6,105,712		
23	Transmission Prepayments (165)	FF1 page 110 Footnote	19,487,085	Line 57	4,911,873	Line 57	642,737	Line 57	(a)
24	Transmission Materials and Supplies	FF1 page 227 Footnote	36,123,136	Line 8	10,822,161	Line 8	3,067,304	Line 8	(a)
	Cash Working Capital								
25	Operation & Maintenance Expense	Sheet 7	37,849,988		10,282,288		6,368,294		(a)
26	Administrative & General Expense	Sheet 7	55,210,887		14,421,742		12,797,566		(b)
27	Subtotal (line 25 26)		93,060,875		24,704,030		19,165,860		(b)
28	x 45 days/360 days	Section II.A.1(I) of Attachment NU-H	0.125		0.125		0.125		(a)
29	Total current Year End (line 27*28)		11,632,609		3,088,004		2,395,733		(b)
30	Prior Year End Cash Working Capital	Note 1	8,827,812		2,426,116		1,703,777		(a)
31	Average Cash Working Capital [(line 29 30)/2]		10,230,211		2,757,060		2,049,755		(b)
32	Construction Work in Progress (13 mo. avg.)	**Attachment A1**	134,757,788		-		4,772,177		(a)
33	AFUDC Regulatory Liability (13 mo. avg.)	**Attachment A1**	54,157,503		-		9,213,804		(a)

Note 1 - Reflects actual information per Eversource's accounting records.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light & Power Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Under Changed Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For Costs in 2014
Sheet 4a

	(A)	(B) YEAR END CAPITALIZATION		(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL		(E) = (C) x (D) WEIGHTED COST OF CAPITAL	(F) = (E) Equity Only EQUITY PORTION
1	LONG-TERM DEBT	$ 2,579,060,322	Note 2	45.78%	5.36%	Note 2	2.45%	
2	PREFERRED STOCK	$ 116,868,097	Note 2	2.07%	4.80%	Note 2	0.10%	0.10%
3	COMMON EQUITY	$ 2,938,441,767	Note 2	52.15%	10.57%	Note 1	5.51%	5.51%
4	TOTAL	$ 5,634,370,186		100.00%			8.06%	5.61%

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 8.06%

(b) Federal Income Tax = ((R.O.E. + (Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate)) / Total Inv. Base (a)) * Federal Income Tax Rate)

	Source	Line 4, Col. (F)	Sheet 7	FF1 page 336 ln. 7b + 10b footnotes	For Costs in 2014	Federal Corporate Tax Rate
6	= ((	5.61%	+ ((428,304)	+ 2,307,409) /	2,275,794,598) *	35.00%)
7			(1	- 35.00%) Federal Corporate Tax Rate		
8	=	3.0652%				

(c) State Income Tax = ((R.O.E. + (Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate)) / Total Inv. Base) + Federal Income Tax) * (State Income Tax Rate)

	Source	Line 4, Col. (F)	Sheet 7	FF1 page 336 ln. 7b + 10b footnotes	For Costs in 2014	Line 8, Col. (B)	Connecticut Corporate Tax Rate
9	= ((	5.61%	+ ((428,304)	+ 2,307,409) /	2,275,794,598) +	3.0652%) * (	9.00%)
10			(1	- 9.00%) Connecticut Corporate Tax Rate			
11	=	0.8662%					

12 (a)+(b)+(c) Cost of Capital Rate = 11.9914%

		Total Transmission	- CWIP	= Total T - Excluding CWIP	Reference
13	INVESTMENT BASE	$2,275,794,598	$80,600,285	$2,195,194,313	For Costs in 2014
14	x Cost of Capital Rate	11.9914%	11.9914%	11.9914%	Line 12
15	= Investment Return and Income Taxes	$272,899,633	$9,665,103	$263,234,531	

Note 1 - ROE per FERC Order in Docket No. ER04-157 dated March 24, 2008.
Note 2 - Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes
(a) Proposed revisions to "Total Inv. Base" reflects the addition of Transmission Merger-Related Costs to Administrative and General Expenses
Source of all other information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247

Public Service Company of New Hampshire
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Under Changed Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For Costs in 2014
Sheet 5a

	(A)	(B) YEAR END CAPITALIZATION		(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL		(E) = (C) x (D) WEIGHTED COST OF CAPITAL	(F) = (E) Equity Only EQUITY PORTION
1	LONG-TERM DEBT	$ 1,070,020,120	Note 2	46.56%	4.15%	Note 2	1.93%	
2	PREFERRED STOCK	$ -	Note 2	0.00%	0.00%	Note 2	0.00%	0.00%
3	COMMON EQUITY	$ 1,228,095,985	Note 2	53.44%	10.57%	Note 1	5.65%	5.65%
4	TOTAL	$ 2,298,116,105		100.00%			7.58%	5.65%

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 7.58%

(b) Federal Income Tax = ((R.O.E. + (Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate)) / Total Inv. Base) * Federal Income Tax Rate)

	Source		R.O.E.		Sheet 7		FF1 page 336 ln. 7b + 10b footnotes		For Costs in 2014		Federal Corporate Tax Rate	
6		= ((	5.65%	+ (	(4,852)	+	230,083	) /	493,913,019	) *	35.00%	)
7				(	1	-	35.00% (Federal Corporate Tax Rate)	)				

8 = 3.0669%

(c) State Income Tax = ((R.O.E. + (Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate)) / Total Inv. Base) + Federal Income Tax) * (State Income Tax Rate)

	Source		R.O.E.		Sheet 7		FF1 page 336 ln. 7b + 10b footnotes		For Costs in 2014				New Hampshire Corporate Tax Rate	
9		= ((	5.65%	+ (	(4,852)	+	230,083	) /	493,913,019	) +	3.0669%	) * (	8.50%	)
10				(	1	-	8.50% (New Hampshire Corporate Tax Rate)	)						

11 = 0.8140%

12 (a)+(b)+(c) Cost of Capital Rate = 11.4609%

		Total Transmission	-	CWIP	=	Total T - Excluding CWIP	Reference
13	INVESTMENT BASE	$493,913,019		-		$493,913,019	For Costs in 2014
14	x Cost of Capital Rate	11.4609%		11.4609%		11.4609%	Line 12
15	= Investment Return and Income Taxes	$56,606,877		-		$56,606,877	

Note 1 - ROE per FERC Order in Docket No. ER04-157 dated March 24, 2008.
Note 2 - Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes

(a) Proposed revisions to "Total Inv. Base" reflects the addition of Transmission Merger-Related Costs to Administrative and General Expenses
Source of all other information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247

Western Massachusetts Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Under Changed Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For Costs in 2014
Sheet 6a

	(A)	(B) YEAR END CAPITALIZATION		(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL		(E) = (C) x (D) WEIGHTED COST OF CAPITAL	(F) = (E) Equity Only EQUITY PORTION
1	LONG-TERM DEBT	$ 567,833,428	Note 2	49.55%	4.31%	Note 2	2.14%	
2	PREFERRED STOCK	$ -	Note 2	0.00%	0.00%	Note 2	0.00%	0.00%
3	COMMON EQUITY	$ 578,162,814	Note 2	50.45%	10.57%	Note 1	5.33%	5.33%
4	TOTAL	$ 1,145,996,242		100.00%			7.47%	5.33%

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 7.47%

(b) Federal Income Tax = ((R.O.E. + (Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / Total Inv. Base) * Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

Source: Sheet 7; FF1 page 336 ln. 7b + 10b footnotes; For Costs in 2014; Federal Corporate Tax Rate

6 = ((5.33% + ((35,604) + 186,099) / 603,466,226) * 35.00%)
7 (1 - 35.00%)
Federal Corporate Tax Rate

8 = 2.8834%

(c) State Income Tax = ((R.O.E. + (Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / Total Inv. Base) + Federal Income Tax) * (State Income Tax Rate) / (1 - State Income Tax Rate)

Source: Sheet 7; FF1 page 336 ln. 7b + 10b footnotes; For Costs in 2014; Massachusetts Corporate Tax Rate

9 = ((5.33% + ((35,604) + 186,099) / 603,466,226) + 2.8834%) * (8.00%)
10 (1 - 8.00%)
Massachusetts Corporate Tax Rate

11 = 0.7164%

12 (a)+(b)+(c) Cost of Capital Rate = 11.0698%

		Total Transmission	- CWIP	= Total T - Excluding CWIP	Reference
13	INVESTMENT BASE	$603,466,226	($4,441,627)	$607,907,853	For Costs in 2014
14	x Cost of Capital Rate	11.0698%	11.0698%	11.0698%	Line 12
15	= Investment Return and Income Taxes	$66,802,504	($491,679)	$67,294,184	

Note 1 - ROE per FERC Order in Docket No. ER04-157 dated March 24, 2008.
Note 2 - Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes

(a) Proposed revisions to "Total Inv. Base" reflects the addition of Transmission Merger-Related Costs to Administrative and General Expenses
Source of all other information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247

CL&P, PSNH, and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Under Changed Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For Costs in 2014
Sheet 7

Line	(A) Description	(B) FF1 Reference	(C) CL&P Year End	(D) FF1 Line	(E) PSNH Year End	(F) FF1 Line	(G) WMECO Year End	(H) FF1 Line	Notes
	Depreciation Expense								
1	Transmission Depreciation	**FF1 page 336**	69,626,166	**7b**	12,792,512	**7b**	15,972,687	**7b**	(a)
2	General Depreciation	**FF1 page 336 footnote**	4,980,574	**10b**	2,727,156	**10b**	789,658	**10b**	(a)
3	AFUDC Regulatory Credit	**Attachment A1**	1,145,364		-		184,386		(a)
4	Dispatch Plant Depreciation ("T" and General)	**Note 1**	1,164,242		-		-		(a)
5	Net Depreciation Expense (line 1+2-3-4)		72,297,134		15,519,668		16,577,959		
6	Amortization of Loss on Reacquired Debt	**FF1 page 114 footnote**	593,685	**64c**	246,881	**64c**	49,668	**64c**	(a)
	Investment Tax Credits								
7	Amortization of Investment Tax Credits	**FF1 page 266 footnote**	(428,304)	**8f**	(4,852)	**8f**	(35,604)	**8f**	(a)
8	Dispatch Center ITC ("T" and General)	**Note 1**	-		-		-		(a)
9	Net Investment Tax Credit (line 7-8)		(428,304)		(4,852)		(35,604)		
	Property Taxes								
10	Transmission Property Taxes	**FF1 page 262 footnote**	45,370,701	**25i**	18,087,310	**Note 3**	18,717,332	**32i**	(a)
11	General Property Taxes (included in line 10)	**Note 2**	-		-		-		(a)
12	Dispatch Center Property Taxes ("T" and General)	**Note 1**	225,879		-		-		(a)
13	Net Property Taxes (line 10+11-12)		45,144,822		18,087,310		18,717,332		
	Payroll Taxes:								
14	Federal Unemployment	**FF1 page 262 footnote**	5,226	**3i**	(51)	**2i**	283	**3i**	(a)
15	FICA	**FF1 page 262 footnote**	233,351	**5i**	(3,062)	**4i**	13,202	**5i**	(a)
16	Medicare	**FF1 page 262 footnote**	65,613	**9i**	(816)	**7i**	3,757	**9i**	(a)
17	CT Unemployment	**FF1 page 262, 262.1, 262 footnote**	16,786	**15i**	(128)	**7i**	852	**13i**	(a)
18	DC Unemployment	**FF1 page 262.1 footnote**	11	**14i**	-		1	**6i**	(a)
19	FL Unemployment	**FF1 page 262.1 footnote**	1	**18i**	-	**27i**	-	**10i**	(a)
20	MI Unemployment	**FF1 page 262.1 footnote**	6	**22i**	-	**31i**	-	**14i**	(a)
21	MA Unemployment	**FF1 page 262, 262.1, 262 footnote**	(285)	**32i**	2	**15i**	69	**22i**	(a)
22	MA Universal Health	**FF1 page 262, 262.1, 262 footnote**	64	**33i**	(1)	**16i**	19	**27i**	(a)
23	NH Unemployment	**FF1 page 262.1, 262, 262 footnote**	1,754	**4i**	(27)	**14i**	108	**37i**	(a)
24	NJ Unemployment	**FF1 page 262 footnote**	-		-		-		(a)
25	NY Unemployment	**FF1 page 262.1 footnote**	-	**10i**	-		-		(a)
26	Total Payroll Tax Exp (sum of line 14 through 25)		322,527		(4,083)		18,291		
	Transmission Operation and Maintenance								
27	Operation and Maintenance	**FF1 page 321**	77,432,007	**112**	51,082,852	**112**	20,725,279	**112**	(a)
28	Transmission of Electricity by Others - #565	**FF1 page 321**	21,727,966	**96**	37,174,569	**96**	13,174,678	**96**	(a)
29		**FF1 page 321**		**84**		**84**		**84**	(a)
30	Account 561.1	**FF1 page 321**	3,245,594	**85**	653,575	**85**	12,368	**85**	(a)
31	Account 561.2	**FF1 page 321**	5,212,556	**86**	474,690	**86**	50,569	**86**	(a)
32	Account 561.3	**FF1 page 321**	2,238,612	**87**	36,962	**87**	13,262	**87**	(a)
33	Account 561.4	**FF1 page 321**	7,157,291	**88**	2,460,768	**88**	1,106,108	**88**	(a)
34	Station Expenses & Rents - #562 / #567	**FF1 page 321**	-	**93+98**	-	**93+98**	-	**93+98**	(a)
35	Net O&M (line 27 - [sum lines 28 through 34])		37,849,988		10,282,288		6,368,294	**Line 23 (H)**	
	Transmission Administrative and General								
36	Administrative and General	**FF1 page 320 footnote**	37,202,294	**197**	10,348,117	**197**	8,041,502	**197**	(a)
37	Transmission Merger-Related Costs	Exhibit No. ES-201, Page 1 of 1	18,008,593	**Line 23 (H)**	4,073,625	**Line 25 (H)**	4,756,064	**Line 26 (H)**	(b)
38	Public Education Expenses	**FF1 page 114 footnote**	-	**49**	-	**49**	-	**49**	(a)
39	Total Administrative and General (line 36+37+38)		55,210,887		14,421,742		12,797,566		(b)

Note 1 - Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.
Note 2 - Reflects actual information per Eversource's accounting records.
Note 3 -This includes local New Hampshire, Vermont, and Maine property taxes (Page 262 ln, 23i, footnote + Page 262 ln, 30i, footnote + Page 262.1 ln, 2i, footnote).

Notes
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Exhibit No. ES-218
Schedule 1

Summary of Impact on Schedule 21-NSTAR's Revenue Requirements under Attachment D to the ISO-NE OATT (1-year amortization)

Eversource Energy Service Company

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-NSTAR Revenue Requirement Comparison Under Present and Changed Rates
Under Attachment D
For the Calendar year 2016

	(A)	(B)		(C)		(D) = (C) - (B)		(E) = (D)/(B)
Line	Description	Net Revenue Requirements under the Present Rates in Attachment D		Net Revenue Requirements under the Changed Rates in Attachment D		Difference		% Difference
1	2016 Estimated Attachment D Revenue Requirements	$ 115,159,162	(1)	$ 116,955,864	(2)	$ 1,797,000	(3)	1.6%

Notes:

(1) Exhibit No. ES-218, Schedule 1, Page 2 of 2, Line 5(B)

(2) Exhibit No. ES-218, Schedule 1, Page 2 of 2, Line 5(C)

(3) In connection with the one-year amortization proposal (with the proposed effective date of June 1, 2016), Eversource is showing the revenue impact for the twelve-month period June 1, 2016 through May 31, 2017. Eversource is using revenue requirement calculations for the calendar year 2016 as an estimate for the twelve-month period beginning June 1, 2016. See Cooper Testimony Exhibit No. ES-200 at 30-31.

	2016	2017	Total
The amounts for each year are as follows:	$ 1,048,250	$ 748,750	$ 1,797,000

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-NSTAR Revenue Requirement Comparison Under Present and Changed Rates
Under Attachment D
For the Calendar year 2016

Line	(A) Description		(B) Net Revenue Requirements under the Present Rates in Attachment D			(C) Net Revenue Requirements under the Changed Rates in Attachment D	
1	Total Schedule 21-NSTAR Revenue Requirements	$	345,401,471	(2)	$	356,075,913	(3)
2	Regional Network Service (RNS) Revenue Credits	$	216,750,485	(4)	$	225,555,225	(5)
3	ISO-NE Scheduling and Dispatch ("S&D") Revenues	$	5,576,120	(1)	$	5,649,120	(6)
4	Other Revenue Credits	$	7,915,704	(1)	$	7,915,704	(1)
5	Net Local Network Service Revenue Requirements (Line 1 - 2 - 3 - 4)	$	115,159,162		$	116,955,864	

Notes:
(1) Source of information is the NSTAR Annual Informational Filing submitted to FERC on August 14, 2015 in Docket No. ER07-549 and ER09-1243.
(2) Exhibit No. ES-218, Schedule 2, Page 1 of 5, Line 11(C)
(3) Exhibit No. ES-218, Schedule 3, Page 1 of 5, Line 11(C)

(4)

Line	Description		Amount		Reference
6	2014 RNS Revenue Credits	$	173,183,026	(1)	
7	Plus: 2015 Forecasted Incremental Estimated PTF Revenue Credits		20,279,943		Exhibit No. ES-215, Schedule 2, Page 1 of 5, Line 4(c)
8	Plus: 2016 Forecasted Incremental Estimated PTF Revenue Credits		24,863,766		Exhibit No. ES-215, Schedule 2, Page 1 of 5, Line 9(c)
9	Less: 2015 Impact on RNS Revenue Credits due to 50 basis points		708,100		(a)
10	Less: 2016 Impact on RNS Revenue Credits due to 50 basis points		868,150		(a)
11	2016 RNS Revenue Credits under Current rates (Lines 6 + 7 + 8 - 9 - 10)	$	216,750,485	To Line 2(B)	

(5)

Line	Description		Amount	Reference
12	2016 RNS Revenue Credits under Current Rates	$	216,750,485	Line 2(B)
13	Plus: Incremental Estimated PTF Revenue Requirements		8,810,000	Exhibit No. ES-215, Schedule 1, Page 1 of 1, Line 1(D)
14	Less: Impact on RNS Revenue Credits due to 50 basis points		5,260	Exhibit No. ES-215, Schedule 3, Page 3 of 5, Line 46, Col.C **Less** Exhibit No. ES-215, Schedule 2, Page 3 of 5, Line 46, Col.C
15	2016 RNS Rev. Credits under Changed Rates (Lines 12 + 13 -14)		225,555,225	To Line 2(C)

(6)

Line	Description		Amount	Reference
16	S&D Revenue Credits under Present Rates	$	5,576,120	Line 3(B)
17	Incremental Estimated PTF Revenue Requirements	$	73,000	Exhibit No. ES-216, Schedule 1, Page 1 of 1, Line 1(D)
18	S&D Revenue Credits under Changed Rates (Line 16 + 17)	$	5,649,120	To Line 3(C)

Line	(a)		2015	Below References from Exhibit No. ES-215 Schedule 2		2016	Below References from Exhibit No. ES-215 Schedule 2
19	NSTAR PTF Plant Additions	$	146,000,000	Page 1 of 5, Line 2(C)	$	179,000,000	Page 1 of 5, Line 7(C)
20	NSTAR Cost of Capital Rate for 50bp Incentive		0.4850%	Page 3 of 5, Line 42(Col. C)		0.4850%	Page 3 of 5, Line 42(Col. C)
21	NSTAR Total (Lines 19 x 20)	$	708,100	To Line 9(B)	$	868,150	To Line 10(B)

Exhibit No. ES-218
Schedule 2

Schedule 21-NSTAR Revenue Requirements under the Present Rates

Eversource Energy Service Company

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-NSTAR Revenue Requirement Under Present Rates
Under Attachment D
For the Calendar year 2016

	(A)	(B)	(C)
Line	**Description**	**Reference**	**Total NSTAR**
1	2014 Actual Schedule 21-NSTAR Revenue Requirement	Exhibit No. ES-218, Schedule 2, Page 2 of 5, Note (d)	$ 280,598,800
2	Estimated 2015 Schedule 21-NSTAR Plant Additions	(1)	$ 196,000,000
3	Carrying Charge Factor (CCF)	Exhibit No. ES-218, Schedule 2, Page 2 of 5, Note (c)	14.6504%
4	2015 Incremental Estimated Schedule 21-NSTAR Revenue Requirement	Line 2 x 3	28,714,784
5	2015 Incremental Estimated Schedule 21-NSTAR CWIP Rev. Req.	(1)	$ 1,366,439
6	Total Estimated Schedule 21-NSTAR Revenue Requirement for 2015	Line 1 + 4 + 5	$ 310,680,023
7	Estimated 2016 Schedule 21-NSTAR Plant Additions	(1)	$ 237,000,000
8	Carrying Charge Factor (CCF)	Line 3	14.6504%
9	2016 Incremental Estimated Schedule 21-NSTAR Revenue Requirement	Line 7 x 8	34,721,448
10	2016 Incremental Estimated Schedule 21-NSTAR CWIP Rev. Req.	(1)	
11	Total Estimated Schedule 21-NSTAR Revenue Requirement for 2016	Line 6 + 9 + 10	$ 345,401,471

Notes:
(1) Based on Eversource's Forecast

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-NSTAR Revenue Requirement Under Present Rates
Under Attachment D
For Costs in 2014
Sheet 1a

	(a)	(b)	(c)	(d)	(e)
Line	**Description**	**Section**	**Amount**	**Reference**	**Notes**
1	**Investment Base**	II.A.1			
2	Transmission Plant	II.A.1.a	$ 1,915,292,693	Sheet 3, Line 1, Col (f)	(a)
3	Transmission Related Intangible & General Plant	II.A.1.b	26,538,303	Sheet 3, Line 4, Col (f)	(a)
4	Transmission Plant Held for Future Use	II.A.1.c	13,571,504	Sheet 3, Line 5, Col (f)	(a)
5	Transmission Related Construction Work in Progress	II.A.1.d	45,961,764	Sheet 3, Line 6, Col (f)	(a)
6	Total Plant		2,001,364,264	Sum Lines 2 thru 5	
7	Trans Related Depreciation and Amortization Reserve	II.A.1.e	(462,609,062)	Sheet 3, Line 12, Col (f)	(a)
8	Transmission Related Accumulated Deferred Taxes	II.A.1.f	(367,674,233)	Sheet 3, Line 20, Col (f)	(a)
9	AFUDC Regulatory Liability	II.A.1.g	(4,435,570)	Sheet 3, Line 21, Col (f)	(a)
10	Total Net Plant		1,166,645,399	Sum Lines 6 thru 9	
11	Transmission Related Gain/Loss on Reacquired Debt	II.A.1.h	3,692,875	Sheet 3, Line 22, Col (f)	(a)
12	Other Trans Related Regulatory Assets/Liabilities	II.A.1.i	24,039,339	Sheet 3, Line 28, Col (f)	(a)
13	Transmission Prepayments	II.A.1.j	56,057,444	Sheet 3, Line 29, Col (f)	(a)
14	Transmission Materials & Supplies	II.A.1.k	28,541,503	Sheet 3, Line 30, Col (f)	(a)
15	Transmission Related Cash Working Capital	II.A.1.l	6,067,021	Sheet 3, Line 35, Col (f)	(b)
16	**Total Investment Base**		$ 1,285,043,581	Sum Lines 10 thru 15	(b)
17	**Revenue Requirement**				
18	Investment Return and Income Taxes	II.A.2	$ 153,380,232	Sheet 2a, Line 39, Col (c)	(b)
19	Transmission Depreciation and Amortization Expense	II.B	42,559,825	Sheet 4 , Line 7, Col (f)	(a)
20	Amortization of Gain/Loss on Reacquired Debt	II.C	286,851	Sheet 4 , Line 8, Col (f)	(a)
21	Transmission Related Amort. of Investment Tax Credits	II.D	(376,034)	Sheet 4 , Line 9, Col (f)	(a)
22	Transmission Related Municipal Tax Expense	II.E	34,612,127	Sheet 4 , Line 10, Col (f)	(a)
23	Transmission Related Payroll Tax Expense	II.F	1,599,627	Sheet 4 , Line 11, Col (f)	(a)
24	Transmission Operation & Maintenance Expense	II.G	25,099,553	Sheet 4 , Line 30, Col (f)	(a)
25	Transmission Related Administrative and General Expense	II.H	19,624,754	Sheet 4 , Line 42, Col (f)	(b)
26	Transmission Related Integrated Facilities Charges	II.I	-	Sheet 5 - Page 1 of 2, Line 6, Col (d)	(a)
27	Transmission Support Revenues	II.J	(4,509,913)	Sheet 5 - Page 1 of 2, Line 45, Col (d)	(a)
28	Transmission Support Expense	II.K	3,811,865	Sheet 5 - Page 1 of 2, Line 57, Col (d)	(a)
29	Transmission Related Expense from Generators	II.L	-	Sheet 5 - Page 1 of 2, Line 60, Col (d)	(a)
30	Transmission Rents Received from Electric Property	II.M	(3,129,907)	Sheet 5 - Page 2 of 2, Line 66, Col (d)	(a)
31	Short-Term and Non-Firm P-T-P Service Revenues	II.N	-	Sheet 5 - Page 2 of 2, Line 69, Col (d)	(a)
32	Regional Network Services (RNS) Revenues	II.O	(173,183,026)	Sheet 5a, Line 6, Col (d)	(a)
33	Through or Out Revenues	II.P	(275,884)	Sheet 5 - Page 2 of 2, Line 78, Col (d)	(a)
34	ISO-NE Scheduling and Dispatch Revenues	II.Q	(5,576,120)	Sheet 5 - Page 2 of 2, Line 82, Col (d)	(a)
35	**Total LNS Revenue Requirement**		$ 93,923,950	Sum Lines 18 thru 34	(b)
36	Wholesale LNS Revenues Received:				
37	MBTA		(904,082)	Sheet 5 - Page 1 of 2, Line 22, Col (c)	(b)
38	Concord		(140,908)	Sheet 5 - Page 1 of 2, Line 23, Col (c)	(b)
39	Massachusetts Port Authority (MASSPORT)		(620,561)	Sheet 5 - Page 1 of 2, Line 24, Col (c)	(b)
40	Nantucket-LNS		(296,522)	Sheet 5 - Page 1 of 2, Line 25, Col (c)	(b)
41	Covanta-SEMass		(133,071)	Sheet 5 - Page 1 of 2, Line 27, Col (c)	(b)
42	Total Wholesale LNS Revenue		$ (2,095,144)	Sum Lines 37 thru 41	(b)
					(b)
43	**Total Retail LNS Revenue Requirement**		**$ 91,828,806**	Line 35 - Line 42	(b)
					(b)
					(b)
44	Average 12 CP				(b)
45	Sum of Monthly Peaks (kW)		48,920,000	FF1 Page 400.17(b) *1000	(b)
46	Average Peak		4,076,667	Line 45 / 12	(b)
					(b)
47	Annual Rate per kW		$ 23.0394	Line 35 / Line 46	(b)
48	Monthly Rate per kW		$ 1.9200	Line 47 / 12	(b)
49	Weekly Rate per kW		$ 0.4431	Line 47 / 52	(b)
50	Daily Rate per kW		$ 0.0631	Line 47 / 365	(b)
51	Hourly Rate per kW		$ 0.0026	Line 47 / 8760	(b)

This reflects an ROE of 10.57% per FERC Order in Docket No. EL11-66 dated October 16, 2014.

Notes:

(a) Source of information is the NSTAR Annual Informational Filing submitted to FERC on August 14, 2015 in Docket No. ER07-549 and ER09-1243.

(b) Source of information is the NSTAR Annual Informational Filing submitted to FERC on August 14, 2015 in Docket No. ER07-549 and ER09-1243. Provided this support because these balances will be revised under the changed rates.

(c) Carrying Charge Factor (Sum Lines 18-25 and 28 / Line 2) 14.6504%

(d) Total LNS Revenue Requirements (Sum Lines 18 - 25 and Line 28) $ 280,598,800

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-NSTAR Revenue Requirement Under Present Rates
Under Attachment D
For Costs in 2014
Sheet 2a

Line	(a) Description	(b) Tariff Section	(c) Balance	(d) Capitalization Ratio	(e) Cost	(f) Weighted Cost	(g) Equity Cost	(h) Reference	(i) Notes
1	**Weighted Cost of Capital**	II.A.2.a							
2	Long Term Debt	II.A.2.a.i	$ 1,792,712,148	41.74%	4.19%	1.75%		FF1 Page 112.24(c)	(a)
3	Preferred Stock	II.A.2.a.ii	43,000,000	1.00%	4.56%	0.05%	0.05%	FF1 Page 112.3(c)	(a)
4	Common Equity	II.A.2.a.iii	2,459,452,736	57.26%	10.57%	6.05%	6.05%	FF1 Page 112.16(c) - Line 3(c)	(a)
5	Total		$ 4,295,164,884			7.85%	6.10%	Sum Lines 2 thru 4	(a)

ROE per ISO New England Inc. Transmission, Markets and Services Tariff, Schedule 21-NSTAR Attachment D II.A.2.(a)(iii), page 60
http://www.iso-ne.com/regulatory/tariff/sect_2/sch21/sch_21_nstar.pdf

Line	Description	Tariff Section	Balance	Reference	Notes
6	**Investment Return**	II.A.2			
7	Total Investment Base		$ 1,285,043,581	Sheet 1, Line 16, Col (c)	(b)
8	Weighted Cost of Capital		7.85%	Line 5, Col (f)	(a)
9	Total Return on Investment		**$ 100,875,921**	Line 7 * Line 8	(b)
10	**Federal Income Tax**	II.A.2.b			
11	A = Equity Cost		6.10%	Line 5, Col (g)	(a)
12	B = Transmission Amortization of ITC		$ (376,034)	Sheet 1, Line 21, Col (c)	(a)
13	C = Equity AFUDC		91,676	FF1 Page 336.7(b) Footnote + FF1 Page 336.10(b) Footnote	(a)
14	Total B + C		(284,358)	Line 12 + Line 13	(a)
15	D = Investment Base		1,285,043,581	Line 7	(b)
16	(B + C) / D		-0.0221%	Line 14 / Line 15	(b)
17	(A + [(C + B) / D]		6.0779%	Line 11 + Line 16	(b)
18	FT = Federal Income Tax Rate		35.00%	Federal corporate tax rate	(a)
19	1 - FT		65.00%	1 - Line 18	(a)
20	Federal Tax Factor		3.2727%	Line 17 * Line 18 / Line 19	(a)
21	Total Federal Income Taxes		**$ 42,055,621**	Line 15 * Line 20	(b)
22	**State Income Tax**	II.A.2.c			
23	A = Equity Cost		6.10%	Line 5, Col (g)	(a)
24	B = Transmission Amortization of ITC		$ (376,034)	Sheet 1, Line 21, Col (c)	(a)
25	C = Equity AFUDC		91,676	FF1 Page 336.7(b) Footnote + FF1 Page 336.10(b) Footnote	(a)
26	Total B + C		(284,358)	Line 24 + Line 25	(a)
27	D = Investment Base		1,285,043,581	Line 7	(b)
28	(B + C) / D		-0.0221%	Line 26 / Line 27	(b)
29	(A + [(C + B) / D]		6.0779%	Line 23 + Line 28	(b)
30	ST = State Income Tax Rate		8.00%	Massachusetts corporate tax rate	(a)
31	1 - ST		92.00%	1 - Line 30	(a)
32	Federal Tax Factor		3.2727%	Line 20	(a)
33	State Tax Factor		0.8131%	(Line 29 + Line 32) * Line 30 / Line 31	(a)
34	Total State Income Taxes		**$ 10,448,689**	Line 27 * Line 33	(b)
35	**Investment Return and Income Taxes**	II.A.2			
36	Return on Investment		$ 100,875,921	Line 9	(b)
37	Federal Income Taxes		42,055,621	Line 21	(b)
38	State Income Taxes		10,448,689	Line 34	(b)
39	**Total Return and Income Taxes**		**$ 153,380,232**	Sum Lines 36 thru 38	(b)

Notes:
(a) Source of information is the NSTAR Annual Informational Filing submitted to FERC on August 14, 2015 in Docket No. ER07-549 and ER09-1243.
(b) Source of information is the NSTAR Annual Informational Filing submitted to FERC on August 14, 2015 in Docket No. ER07-549 and ER09-1243.
Provided this support because these balances will be revised under the changed rates.

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-NSTAR Revenue Requirement Under Present Rates
Under Attachment D
For Costs in 2014
Sheet 3

	(a)	(b)	(c)	(d)	(e)	(f)	(g)		(h)
		Tariff		Allocations					
Line	Description	Section	Total	Allocator	Factor	LNS Amount	Reference		Notes
1	**Transmission Plant**	II.A.1.a	$ 1,915,292,693	Direct	100.0000%	$ 1,915,292,693	FF1 Page 207.58(g)	(a)	
2	General Plant		186,941,660	W&S	12.8871%	24,091,359	FF1 Page 207.99(g)	(a)	
3	Intangible Plant		18,987,542	W&S	12.8871%	2,446,944	FF1 Page 205.5(g)	(a)	
4	**Total Intangible & General Plant**	II.A.1.b				26,538,303	Sum Lines 2 thru 3		
5	**Transmission Plant Held for Future Use**	II.A.1.c	13,571,504	Direct	100.0000%	13,571,504	FF1 Page 214.14(d) + FF1 Page 214.15(d) + FF1 Page 214.16(d) + FF1 Page 214.17(d) + FF1 Page 214.18(d)	(a)	
6	**Transmission Related CWIP - Note 1**	II.A.1.d	91,923,527	CWIP	50.0000%	45,961,764	FF1 Page 216, lines 32(b), 34(b) thru 42(b), and Page 216.1, lines 1(b), 2(b), 5(b), 6(b), 10(b) thru 12(b) 14(part)(b) Trans only	(a)	
7	**Transmission Related Dep & Amort Reserve**	II.A.1.e							
8	Transmission Accumulated Depreciation		(453,776,651)	Direct	100.0000%	(453,776,651)	FF1 Page 219.25(b)	(a)	
9	General Plant Accumulated Depreciation		(52,490,917)	W&S	12.8871%	(6,764,557)	FF1 Page 219.28(b)	(a)	
10	General Plant Accumulated Amortization		(6,245,258)	W&S	12.8871%	(804,833)	FF1 Page 200.21(c) Footnote	(a)	
11	Intangible Plant Accumulated Amortization		(9,800,663)	W&S	12.8871%	(1,263,021)	FF1 Page 200.21(c) Footnote	(a)	
12	Total Transmission Related Depreciation Reserve		(522,313,489)			(462,609,062)	Sum Lines 8 thru 11		
13	**Transmission Accumulated Deferred Taxes**	II.A.1.f							
14	Accumulated Deferred Taxes (190)		63,896,752		13.6034%	8,692,119	Sheet 8, Line 12, col (d)	(a)	
15	Accumulated Deferred Income Taxes (281)		-			-	FF1 Page 113.62(c)	(a)	
16	Accumulated Deferred Taxes - Property (282)		(1,143,462,163)				FF1 Page 275.9(k)	(a)	
17	Less Transition Property		-				FF1 Page 275.4(k)	(a)	
18	Net Acc. Def. Income Taxes - Other Property (282)		(1,143,462,163)	Plant	28.7026%	(328,203,371)	Sum Lines 16 thru 17		
19	Accumulated Deferred Income Taxes - Other (283)		(506,588,448)		9.5073%	(48,162,981)	Sheet 8, Line 27, col (d)	(a)	
20	Total					(367,674,233)	Line 14 + Line 15 + Line 18 + Line 19		
21	**AFUDC Regulatory Liability**	II.A.1.g	(4,435,570)	Direct	100.0000%	(4,435,570)	FF1 Page 278.3(f)	(a)	
								(a)	
22	**Gain/Loss on Reacquired Debt**	II.A.1.h	12,865,994	Plant	28.7026%	3,692,875	FF1 Page 111.81(c) + FF1 Page 113.61(c)		
23	**Other Regulatory Assets**	II.A.1.i							
24	FAS 106 (182.3 & 254)		-	W&S	12.8871%	-	FF1 Page 232	(a)	
25	ASC 740 (182.3 - FAS 109)		87,768,732				FF1 Page 232.29(f)	(a)	
26	Less ASC 740 Liability (254 - FAS 109)		(4,015,556)				FF1 Page 278.1(f)	(a)	
27	Net ASC 740 (182.3 & 254 - FAS 109)		83,753,176	Plant	28.7026%	24,039,339	Sum Lines 25 thru 26	(a)	
28	Total Other Regulatory Assets		83,753,176			24,039,339	Line 24 + line 27	(a)	
29	**Prepayments**	II.A.1.j	434,988,820	W&S	12.8871%	56,057,444	FF1 Page 111.57(c) + FF1 Page 232.1.2(f) +Page 232.1.3(f)	(a)	
30	**Transmission Materials & Supplies**	II.A.1.k	28,541,503	Direct	100.0000%	28,541,503	FF1 Page 227.8(c) + FF1 Page 227.5(c) Footnote	(a)	
31	**Cash Working Capital**	II.A.1.l							
32	Operation & Maintenance Expense		25,099,553	WC	12.5000%	3,137,444	Sheet 1a, Line 24, col (c)	(a)	
33	Administrative & General Expense		19,624,754	WC	12.5000%	2,453,094	Sheet 1a, Line 25, col (c)	(b)	
34	Transmission Support Expenses		3,811,865	WC	12.5000%	476,483	Sheet 1a, Line 28, col (c)	(a)	
35	Total Cash Working Capital		48,536,172			6,067,021	Sum Lines 32 thru 34	(b)	

Line	Description	Allocation Factor	Reference	
36				
37	Direct Allocation (Direct)	100.0000%		(a)
38	Wages & Salary (W&S)	12.8871%	Sheet 6, Line 6(c)	(a)
39	Plant Allocation (Plant)	28.7026%	Sheet 6, Line 14(c)	(a)
40	Construction Work in Progress Allocation (CWIP)	50.0000%	Sheet 6, Line 15(c)	(a)
41	Cash Working Capital (WC)	12.50%	Tariff Section II.A.1.l	(a)

42 **Note 1 -** Internal Records identify CWIP projects for rate base, as noted in the Exhibit "2014 Construction Work in Progress" included in this filing.

Notes:
(a) Source of information is the NSTAR Annual Informational Filing submitted to FERC on August 14, 2015 in Docket No. ER07-549 and ER09-1243.
(b) Source of information is the NSTAR Annual Informational Filing submitted to FERC on August 14, 2015 in Docket No. ER07-549 and ER09-1243. Provided this support because these balances will be revised under the changed rates.

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-NSTAR Revenue Requirement Under Present Rates
Under Attachment D
For Costs in 2014
Sheet 4

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
Line	**Description**	**Tariff Section**	**Total**	**Allocator**	**Factor**	**Allocations LNS Amount**	**Reference**	**Notes**
1	**Transmission Depreciation and Amortization Expense**	II.B						
2	Transmission Depreciation	II.B.i	$ 41,001,613	Direct	100.0000%	$ 41,001,613	FF1 Page 336.7(f)	(a)
3	General Plant Depreciation and Amortization	II.B.ii	8,991,113	W&S	12.8871%	1,158,694	FF1 Page 336.10(f)	(a)
4	Amortization of Transmission Related Intangible Plant		4,111,761	W&S	12.8871%	529,887	FF1 Page 336.1(f)	(a)
5	Amortization of AFUDC Regulatory Credit		(130,369)			(130,369)	FF1 Page 114.13(c)	(a)
6	Net Amortization of Transmission Related Intangible Plant		$ 3,981,392			$ 399,518	Sum Lines 4 and 5	(a)
7	Total Transmission Depreciation and Amortization Expense		$ 53,974,118			$ 42,559,825	Sum Lines 2, 3 and 6	(a)
8	**Amortization of Gain/Loss on Reacquired Debt**	II.C	$ 999,391	Plant	28.7026%	$ 286,851	FF1 Page 117.64(c) + FF1 Page 117.66(c)	(a)
9	**Transmission Related Amortization of ITC**	II.D	$ (1,310,106)	Plant	28.7026%	$ (376,034)	FF1 Page 114.19(c)	(a)
10	**Transmission Related Municipal Tax Expense**	II.E	$ 120,588,821	Plant	28.7026%	$ 34,612,127	FF1 Page 263.5(i)	(a)
11	**Transmission Related Payroll Tax Expense**	II.F	$ 12,412,619	W&S	12.8871%	$ 1,599,627	FF1 Page 263.10(i)	(a)
12	**Transmission Operation and Maintenance Expense**	II.G						
13	Operation Supervision & Engineering (560)		$ 5,674,265	Direct	100.0000%	5,674,265	FF1 Page 321.83(b)	(a)
14			-	Internal Costs		-	FF1 Page 321.84(b)	(a)
15	Load Dispatch - Reliability (561.1)		1,389,220	Internal Costs		1,389,220	FF1 Page 321.85(b)	(a)
16	Load Dispatch-Monitor and Operate Transmission System (561.2)		1,311,222	Internal Costs		1,311,222	FF1 Page 321.86(b)	(a)
17	Load Dispatch-Transmission Service and Scheduling (561.3)		570,681	Internal Costs		570,681	FF1 Page 321.87(b)	(a)
18	Scheduling, System Control and Dispatch Services (561.4)		12,155,295	External Costs		-	FF1 Page 321.88(b)	(a)
19	Reliability, Planning and Standards Development (561.5)		273,226	Internal Costs		21,719	FF1 Page 321.89(b)	(a)
20	Transmission Service Studies (561.6)		106	Internal Costs		106	FF1 Page 321.90(b)	(a)
21	Generation Interconnection Studies (561.7)		-	Internal Costs		-	FF1 Page 321.91(b)	(a)
22	Reliability, Planning and Standards Development Services (561.8)		53,935	External Costs		-	FF1 Page 321.92(b)	(a)
23	Station Expenses (562)		2,729,963	Direct	100.0000%	2,729,963	FF1 Page 321.93(b)	(a)
24	Overhead Lines Expenses (563)		4,327,839	Direct	100.0000%	4,327,839	FF1 Page 321.94(b)	(a)
25	Underground Lines Expenses (564)		636,122	Direct	100.0000%	636,122	FF1 Page 321.95(b)	(a)
26	Miscellaneous Transmission Expenses (566)		496,506	Direct	100.0000%	496,506	FF1 Page 321.97(b)	(a)
27	Rents (567)		14,755	Direct	100.0000%	14,755	Sheet 5 - Page 1 of 2, Line 3, col (d)	(a)
28	Transmission Maintenance (568 - 573)		7,927,155	Direct	100.0000%	7,927,155	FF1 Page 321.111(b)	(a)
29	Regional Market Expense (575-576)		424,648	External Costs	0.0000%	-	FF1 Page 322.131(b)	(a)
30	Total Transmission O&M Expense		$ 37,984,938			$ 25,099,553	Sum Lines 13 thru 29	
31	**Transmission Related A&G Expenses**	II.H						
32	Administrative and General Expenses	I.B	$ 145,329,829				FF1 Page 323.197(b)	(a)
33	Property Insurance (924)		(926,016)				FF1 Page 323.185(b)	(a)
34	Employee Pensions and Benefits (926)		(51,124,252)				FF1 Page 323.187(b)	(a)
35	Regulatory Commission Expenses (928)		(9,560,209)				FF1 Page 323.189(b)	(a)
36	General Advertising Expenses (930.1)		(32,018)				FF1 Page 323.191(b)	(a)
37	Miscellaneous General Expenses (930.2) - **Note 2**		(52,118)				FF1 Page 232.2.14(e)	(a)
38	Sub-Total	II.H.1	83,635,216	W&S	12.8871%	10,778,154	Sum Lines 32 thru 37	(b)
39	Property Insurance (924)	II.H.2	926,016	Plant	28.7026%	265,791	Line 33	(a)
40	Employee Pensions and Benefits (926) - **Note 1**	II.H.1	51,124,252	W&S	12.8871%	6,588,433	Line 34	(a)
41	Regulatory Commission Expenses (928)	II.H.3	9,560,209	Footnote	20.8403%	1,992,376	Line 48	(a)
42	Total Transmission Related A&G Expenses		$ 145,245,693			$ 19,624,754	Sum Lines 38 thru 41	(b)
43	Regulatory Commission Expenses (928)	II.H.3						(a)
44	Assessment Charged by the MA DPU		$ 6,712,589		0.0000%	$ -	FF1 Page 350.2(d)	(a)
45	Proportionate share of expenses of FERC Assessment Order No. 472		1,992,376	Direct	100.0000%	1,992,376	FF1 Page 350.6(d)	(a)
46	Legal Fees - Distribution		787,573		0.0000%	-	FF1 Page 350.8(d)	(a)
47	Minor items - Distribution		67,671		0.0000%	-	FF1 Page 350.10(d)	(a)
48	Total Regulatory Commission Expenses	II.H.3	$ 9,560,209		20.8403%	$ 1,992,376	Sum Lines 44 thru 47	(a)

Line	Description	Allocation Factor	Reference	Notes
49	**Description**	**Allocation Factor**	**Reference**	
50	Direct Allocation (Direct)	100.0000%		(a)
51	Wages & Salaries Allocation (W&S)	12.8871%	Sheet 6, Line 6(c)	(a)
52	Plant Allocation (Plant)	28.7026%	Sheet 6, Line 14(c)	(a)

53 **Note 1**
54 Included in the Employee Pension and Benefits Expenses are costs related to Post Retirement Benefits other than Pension (PBOP). PBOP costs are determined by an independent actuary
55 as required by ASC 715. The PBOP expense included in Account 926 for 2014 was ($5,000,000) as compared to $4,600,000 in 2013; as shown on the FF1, page 323, footnote.
56 Applying the labor allocator to the total PBOP expense results in $(251,041) of PBOP expense being recovered through the LNS Tariff in 2014, as compared to $249,762 in the prior year.

Line		2014	2013		Notes
57	PBOP	$ (5,000,000)	$ 4,600,000	Page 323 line 187 footnote	(a)
58	Capitalized PBOP & Other impact adjustment	3,052,000	(1,866,000)	**Note 3**	(a)
59	Net PBOP in account 926	$ (1,948,000)	$ 2,734,000	Line 57 + Line 58	(a)
60	Wages & Salaries Allocation (W&S)	12.8871%	9.1354%	Sheet 6	(a)
61	LNS portion of PBOP	$ (251,041)	$ 249,762	Line 59 x Line 60	(a)

62 **Note 2 -** NSTAR Green Program costs are excludable for Transmission billing purposes. Reflects actual information per the Company's accounting records.
63 **Note 3** - Reflects actual information per the Company's accounting records. ;

Notes:
(a) Source of information is the NSTAR Annual Informational Filing submitted to FERC on August 14, 2015 in Docket No. ER07-549 and ER09-1243.
(b) Source of information is the NSTAR Annual Informational Filing submitted to FERC on August 14, 2015 in Docket No. ER07-549 and ER09-1243. Provided this support because these balances will be revised under the changed rates.

Exhibit No. ES-218
Schedule 3

Schedule 21-NSTAR Revenue Requirements under the Changed Rates

Eversource Energy Service Company

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-NSTAR Revenue Requirement Under Changed Rates
Under Attachment D
For the Calendar year 2016

	(A)	(B)	(C)
Line	Description	Reference	Total NSTAR
1	2014 Actual Schedule 21-NSTAR Revenue Requirement	Exhibit No. ES-218, Schedule 3, Page 2 of 5, Note (c)	$ 291,273,242
2	Estimated 2015 Schedule 21-NSTAR Plant Additions	(1)	$ 196,000,000
3	Carrying Charge Factor (CCF)	Exhibit No. ES-218, Schedule 2, Page 2 of 5, Note (c)	14.6504%
4	2015 Incremental Estimated Schedule 21-NSTAR Revenue Requirement	Line 2 x 3	28,714,784
5	2015 Incremental Estimated Schedule 21-NSTAR CWIP Revenue Requirements	(1)	$ 1,366,439
6	Total Estimated Schedule 21-NSTAR Revenue Requirement for 2015	Line 1 + 4 + 5	$ 321,354,465
7	Estimated 2016 Schedule 21-NSTAR Plant Additions	(1)	$ 237,000,000
8	Carrying Charge Factor (CCF)	Line 3	14.6504%
9	2016 Incremental Estimated Schedule 21-NSTAR Revenue Requirement	Line 7 x 8	34,721,448
10	2016 Incremental Estimated Schedule 21-NSTAR CWIP Revenue Requirements	(1)	$ -
11	Total Estimated Schedule 21-NSTAR Revenue Requirement for 2016	Line 6 + 9 + 10	$ 356,075,913

Notes:
(1) Based on Eversource's Forecast

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-NSTAR Revenue Requirement Under Changed Rates
Under Attachment D
For Costs in 2014
Sheet 1a

	(a)	(b)	(c)		(d)	(e)
Line	**Description**	**Section**	**Amount**		**Reference**	**Notes**
1	**Investment Base**	II.A.1				
2	Transmission Plant	II.A.1.a	$	1,915,292,693	Sheet 3, Line 1, Col (f)	(a)
3	Transmission Related Intangible & General Plant	II.A.1.b		26,538,303	Sheet 3, Line 4, Col (f)	(a)
4	Transmission Plant Held for Future Use	II.A.1.c		13,571,504	Sheet 3, Line 5, Col (f)	(a)
5	Transmission Related Construction Work in Progress	II.A.1.d		45,961,764	Sheet 3, Line 6, Col (f)	(a)
6	Total Plant			2,001,364,264	Sum Lines 2 thru 5	
7	Trans Related Depreciation and Amortization Reserve	II.A.1.e		(462,609,062)	Sheet 3, Line 12, Col (f)	(a)
8	Transmission Related Accumulated Deferred Taxes	II.A.1.f		(367,674,233)	Sheet 3, Line 20, Col (f)	(a)
9	AFUDC Regulatory Liability	II.A.1.g		(4,435,570)	Sheet 3, Line 21, Col (f)	(a)
10	Total Net Plant			1,166,645,399	Sum Lines 6 thru 9	
11	Transmission Related Gain/Loss on Reacquired Debt	II.A.1.h		3,692,875	Sheet 3, Line 22, Col (f)	(a)
12	Other Trans Related Regulatory Assets/Liabilities	II.A.1.i		24,039,339	Sheet 3, Line 28, Col (f)	(a)
13	Transmission Prepayments	II.A.1.j		56,057,444	Sheet 3, Line 29, Col (f)	(a)
14	Transmission Materials & Supplies	II.A.1.k		28,541,503	Sheet 3, Line 30, Col (f)	(a)
15	Transmission Related Cash Working Capital	II.A.1.l		7,381,712	Sheet 3, Line 35, Col (f)	(b)
16	**Total Investment Base**		$	1,286,358,272	Sum Lines 10 thru 15	(b)
17	**Revenue Requirement**					
18	Investment Return and Income Taxes	II.A.2	$	153,537,150	Sheet 2a, Line 39, Col (c)	(b)
19	Transmission Depreciation and Amortization Expense	II.B		42,559,825	Sheet 4 , Line 7, Col (f)	(a)
20	Amortization of Gain/Loss on Reacquired Debt	II.C		286,851	Sheet 4 , Line 8, Col (f)	(a)
21	Transmission Related Amort. of Investment Tax Credits	II.D		(376,034)	Sheet 4 , Line 9, Col (f)	(a)
22	Transmission Related Municipal Tax Expense	II.E		34,612,127	Sheet 4 , Line 10, Col (f)	(a)
23	Transmission Related Payroll Tax Expense	II.F		1,599,627	Sheet 4 , Line 11, Col (f)	(a)
24	Transmission Operation & Maintenance Expense	II.G		25,099,553	Sheet 4 , Line 30, Col (f)	(a)
25	Transmission Related Administrative and General Expense	II.H		30,142,278	Sheet 4 , Line 44, Col (f)	(b)
26	Transmission Related Integrated Facilities Charges	II.I		-	Sheet 5 - Page 1 of 2, Line 6, Col (d)	(a)
27	Transmission Support Revenues	II.J		(4,509,913)	Sheet 5 - Page 1 of 2, Line 45, Col (d)	(a)
28	Transmission Support Expense	II.K		3,811,865	Sheet 5 - Page 1 of 2, Line 57, Col (d)	(a)
29	Transmission Related Expense from Generators	II.L		-	Sheet 5 - Page 1 of 2, Line 60, Col (d)	(a)
30	Transmission Rents Received from Electric Property	II.M		(3,129,907)	Sheet 5 - Page 2 of 2, Line 66, Col (d)	(a)
31	Short-Term and Non-Firm P-T-P Service Revenues	II.N		-	Sheet 5 - Page 2 of 2, Line 69, Col (d)	(a)
32	Regional Network Services (RNS) Revenues	II.O		(173,183,026)	Sheet 5a, Line 6, Col (d)	(a)
33	Through or Out Revenues	II.P		(275,884)	Sheet 5 - Page 2 of 2, Line 78, Col (d)	(a)
34	ISO-NE Scheduling and Dispatch Revenues	II.Q		(5,576,120)	Sheet 5 - Page 2 of 2, Line 82, Col (d)	(a)
35	**Total LNS Revenue Requirement**		$	104,598,392	Sum Lines 18 thru 34	(b)
36	Wholesale LNS Revenues Received:					
37	MBTA			(904,082)	Sheet 5 - Page 1 of 2, Line 22, Col (c)	(b)
38	Concord			(140,908)	Sheet 5 - Page 1 of 2, Line 23, Col (c)	(b)
39	Massachusetts Port Authority (MASSPORT)			(620,561)	Sheet 5 - Page 1 of 2, Line 24, Col (c)	(b)
40	Nantucket-LNS			(296,522)	Sheet 5 - Page 1 of 2, Line 25, Col (c)	(b)
41	Covanta-SEMass			(133,071)	Sheet 5 - Page 1 of 2, Line 27, Col (c)	(b)
42	Total Wholesale LNS Revenue		$	(2,095,144)	Sum Lines 37 thru 41	(b)
						(b)
43	**Total Retail LNS Revenue Requirement**		**$**	**102,503,248**	Line 35 - Line 42	(b)
						(b)
						(b)
44	Average 12 CP					(b)
45	Sum of Monthly Peaks (kW)			48,920,000	FF1 Page 400.17(b) *1000	(b)
46	Average Peak			4,076,667	Line 45 / 12	(b)
						(b)
47	Annual Rate per kW		$	25.6578	Line 35 / Line 46	(b)
48	Monthly Rate per kW		$	2.1382	Line 47 / 12	(b)
49	Weekly Rate per kW		$	0.4934	Line 47 / 52	(b)
50	Daily Rate per kW		$	0.0703	Line 47 / 365	(b)
51	Hourly Rate per kW		$	0.0029	Line 47 / 8760	(b)

This reflects an ROE of 10.57% per FERC Order in Docket No. EL11-66 dated October 16, 2014.

Notes:

(a) Source of information is the NSTAR Annual Informational Filing submitted to FERC on August 14, 2015 in Docket No. ER07-549 and ER09-1243.
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses
(c) Total LNS Revenue Requirements (Sum Lines 18 - 25 and Line 28) $ 291,273,242

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-NSTAR Revenue Requirement Under Changed Rates
Under Attachment D
For Costs in 2014
Sheet 2a

Line	(a) Description	(b) Tariff Section	(c) Balance	(d) Capitalization Ratio	(e) Cost	(f) Weighted Cost	(g) Equity Cost	(h) Reference	(i) Notes
1	**Weighted Cost of Capital**	II.A.2.a							
2	Long Term Debt	II.A.2.a.i	$ 1,792,712,148	41.74%	4.19%	1.75%		FF1 Page 112.24(c)	(a)
3	Preferred Stock	II.A.2.a.ii	43,000,000	1.00%	4.56%	0.05%	0.05%	FF1 Page 112.3(c)	(a)
4	Common Equity	II.A.2.a.iii	2,459,452,736	57.26%	10.57%	6.05%	6.05%	FF1 Page 112.16(c) - Line 3(c)	(a)
5	Total		$ 4,295,164,884			7.85%	6.10%	Sum Lines 2 thru 4	(a)

ROE per ISO New England Inc. Transmission, Markets and Services Tariff, Schedule 21-NSTAR Attachment D II.A.2.(a)(iii), page 60
http://www.iso-ne.com/regulatory/tariff/sect_2/sch21/sch_21_nstar.pdf

Line	(a) Description	(b) Tariff Section	(c) Balance	(h) Reference	(i) Notes
6	**Investment Return**	II.A.2			
7	Total Investment Base		$ 1,286,358,272	Sheet 1, Line 16, Col (c)	(b)
8	Weighted Cost of Capital		7.85%	Line 5, Col (f)	(a)
9	Total Return on Investment		**$ 100,979,124**	Line 7 * Line 8	(b)
10	**Federal Income Tax**	II.A.2.b			
11	A = Equity Cost		6.10%	Line 5, Col (g)	(a)
12	B = Transmission Amortization of ITC		$ (376,034)	Sheet 1, Line 21, Col (c)	(a)
13	C = Equity AFUDC		91,676	FF1 Page 336.7(b) Footnote + FF1 Page 336.10(b) Footnote	(a)
14	Total B + C		(284,358)	Line 12 + Line 13	(a)
15	D = Investment Base		1,286,358,272	Line 7	(b)
16	(B + C) / D		-0.0221%	Line 14 / Line 15	(b)
17	(A + [(C + B) / D]		6.0779%	Line 11 + Line 16	(b)
18	FT = Federal Income Tax Rate		35.00%	Federal corporate tax rate	(a)
19	1 - FT		65.00%	1 - Line 18	(a)
20	Federal Tax Factor		3.2727%	Line 17 * Line 18 / Line 19	(a)
21	Total Federal Income Taxes		**$ 42,098,647**	Line 15 * Line 20	(b)
22	**State Income Tax**	II.A.2.c			
23	A = Equity Cost		6.10%	Line 5, Col (g)	(a)
24	B = Transmission Amortization of ITC		$ (376,034)	Sheet 1, Line 21, Col (c)	(a)
25	C = Equity AFUDC		91,676	FF1 Page 336.7(b) Footnote + FF1 Page 336.10(b) Footnote	(a)
26	Total B + C		(284,358)	Line 24 + Line 25	(a)
27	D = Investment Base		1,286,358,272	Line 7	(b)
28	(B + C) / D		-0.0221%	Line 26 / Line 27	(b)
29	(A + [(C + B) / D]		6.0779%	Line 23 + Line 28	(b)
30	ST = State Income Tax Rate		8.00%	Massachusetts corporate tax rate	(a)
31	1 - ST		92.00%	1 - Line 30	(a)
32	Federal Tax Factor		3.2727%	Line 20	(a)
33	State Tax Factor		0.8131%	(Line 29 + Line 32) * Line 30 / Line 31	(a)
34	Total State Income Taxes		**$ 10,459,379**	Line 27 * Line 33	(b)
35	**Investment Return and Income Taxes**	II.A.2			
36	Return on Investment		$ 100,979,124	Line 9	(b)
37	Federal Income Taxes		42,098,647	Line 21	(b)
38	State Income Taxes		10,459,379	Line 34	(b)
39	**Total Return and Income Taxes**		**$ 153,537,150**	Sum Lines 36 thru 38	(b)

Notes:
(a) Source of information is the NSTAR Annual Informational Filing submitted to FERC on August 14, 2015 in Docket No. ER07-549 and ER09-1243.
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-NSTAR Revenue Requirement Under Changed Rates
Under Attachment D
For Costs in 2014
Sheet 3

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		Tariff		Allocations				
Line	Description	Section	Total	Allocator	Factor	LNS Amount	Reference	Notes
1	**Transmission Plant**	II.A.1.a	$ 1,915,292,693	Direct	100.0000%	$ 1,915,292,693	FF1 Page 207.58(g)	(a)
2	General Plant		186,941,660	W&S	12.8871%	24,091,359	FF1 Page 207.99(g)	(a)
3	Intangible Plant		18,987,542	W&S	12.8871%	2,446,944	FF1 Page 205.5(g)	(a)
4	**Total Intangible & General Plant**	II.A.1.b				26,538,303	Sum Lines 2 thru 3	
5	**Transmission Plant Held for Future Use**	II.A.1.c	13,571,504	Direct	100.0000%	13,571,504	FF1 Page 214.14(d) + FF1 Page 214.15(d) + FF1 Page 214.16(d) + FF1 Page 214.17(d) + FF1 Page 214.18(d)	(a)
6	**Transmission Related CWIP - Note 1**	II.A.1.d	91,923,527	CWIP	50.0000%	45,961,764	FF1 Page 216, lines 32(b), 34(b) thru 42(b), and Page 216.1, lines 1(b), 2(b), 5(b), 6(b), 10(b) thru 12(b) 14(part)(b) Trans only	(a)
7	**Transmission Related Dep & Amort Reserve**	II.A.1.e						
8	Transmission Accumulated Depreciation		(453,776,651)	Direct	100.0000%	(453,776,651)	FF1 Page 219.25(b)	(a)
9	General Plant Accumulated Depreciation		(52,490,917)	W&S	12.8871%	(6,764,557)	FF1 Page 219.28(b)	(a)
10	General Plant Accumulated Amortization		(6,245,258)	W&S	12.8871%	(804,833)	FF1 Page 200.21(c) Footnote	(a)
11	Intangible Plant Accumulated Amortization		(9,800,663)	W&S	12.8871%	(1,263,021)	FF1 Page 200.21(c) Footnote	(a)
12	Total Transmission Related Depreciation Reserve		(522,313,489)			(462,609,062)	Sum Lines 8 thru 11	
13	**Transmission Accumulated Deferred Taxes**	II.A.1.f						
14	Accumulated Deferred Taxes (190)		63,896,752		13.6034%	8,692,119	Sheet 8, Line 12, col (d)	(a)
15	Accumulated Deferred Income Taxes (281)		-			-	FF1 Page 113.62(c)	(a)
16	Accumulated Deferred Taxes - Property (282)		(1,143,462,163)				FF1 Page 275.9(k)	(a)
17	Less Transition Property		-				FF1 Page 275.4(k)	(a)
18	Net Acc. Def. Income Taxes - Other Property (282)		(1,143,462,163)	Plant	28.7026%	(328,203,371)	Sum Lines 16 thru 17	
19	Accumulated Deferred Income Taxes - Other (283)		(506,588,448)		9.5073%	(48,162,981)	Sheet 8, Line 27, col (d)	(a)
20	Total					(367,674,233)	Line 14 + Line 15 + Line 18 + Line 19	
21	**AFUDC Regulatory Liability**	II.A.1.g	(4,435,570)	Direct	100.0000%	(4,435,570)	FF1 Page 278.3(f)	(a) (a)
22	**Gain/Loss on Reacquired Debt**	II.A.1.h	12,865,994	Plant	28.7026%	3,692,875	FF1 Page 111.81(c) + FF1 Page 113.61(c)	
23	**Other Regulatory Assets**	II.A.1.i						
24	FAS 106 (182.3 & 254)		-	W&S	12.8871%	-	FF1 Page 232	(a)
25	ASC 740 (182.3 - FAS 109)		87,768,732				FF1 Page 232.29(f)	(a)
26	Less ASC 740 Liability (254 - FAS 109)		(4,015,556)				FF1 Page 278.1(f)	(a)
27	Net ASC 740 (182.3 & 254 - FAS 109)		83,753,176	Plant	28.7026%	24,039,339	Sum Lines 25 thru 26	(a)
28	Total Other Regulatory Assets		83,753,176			24,039,339	Line 24 + line 27	(b)
29	**Prepayments**	II.A.1.j	434,988,820	W&S	12.8871%	56,057,444	FF1 Page 111.57(c) + FF1 Page 232.1.2(f) +Page 232.1.3(f)	(a)
30	**Transmission Materials & Supplies**	II.A.1.k	28,541,503	Direct	100.0000%	28,541,503	FF1 Page 227.8(c) + FF1 Page 227.5(c) Footnote	(a)
31	**Cash Working Capital**	II.A.1.l						
32	Operation & Maintenance Expense		25,099,553	WC	12.5000%	3,137,444	Sheet 1a, Line 24, col (c)	(a)
33	Administrative & General Expense		30,142,278	WC	12.5000%	3,767,785	Sheet 1a, Line 25, col (c)	(b)
34	Transmission Support Expenses		3,811,865	WC	12.5000%	476,483	Sheet 1a, Line 28, col (c)	(a)
35	Total Cash Working Capital		59,053,696			7,381,712	Sum Lines 32 thru 34	(b)

Line	Description	Allocation Factor	Reference	Notes
36	**Description**	**Allocation Factor**	**Reference**	
37	Direct Allocation (Direct)	100.0000%		(a)
38	Wages & Salary (W&S)	12.8871%	Sheet 6, Line 6(c)	(a)
39	Plant Allocation (Plant)	28.7026%	Sheet 6, Line 14(c)	(a)
40	Construction Work in Progress Allocation (CWIP)	50.0000%	Sheet 6, Line 15(c)	(a)
41	Cash Working Capital (WC)	12.50%	Tariff Section II.A.1.l	(a)

42 **Note 1 -** Internal Records identify CWIP projects for rate base, as noted in the Exhibit "2014 Construction Work in Progress" included in this filing.

Notes:
(a) Source of information is the NSTAR Annual Informational Filing submitted to FERC on August 14, 2015 in Docket No. ER07-549 and ER09-1243.
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Eversource Energy
Exhibit No. ES-218
Schedule 3

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-NSTAR Revenue Requirement Under Changed Rates
Under Attachment D
For Costs in 2014
Sheet 4

Line	(a) Description	(b) Tariff Section	(c) Total	(d) Allocator	(e) Factor	(f) Allocations LNS Amount	(g) Reference	(h) Notes
1	**Transmission Depreciation and Amortization Expense**	II.B						
2	Transmission Depreciation	II.B.i	$ 41,001,613	Direct	100.0000%	$ 41,001,613	FF1 Page 336.7(f)	(a)
3	General Plant Depreciation and Amortization	II.B.ii	8,991,113	W&S	12.8871%	1,158,694	FF1 Page 336.10(f)	(a)
4	Amortization of Transmission Related Intangible Plant		4,111,761	W&S	12.8871%	529,887	FF1 Page 336.1(f)	(a)
5	Amortization of AFUDC Regulatory Credit		(130,369)			(130,369)	FF1 Page 114.13(c)	(a)
6	Net Amortization of Transmission Related Intangible Plant		$ 3,981,392			$ 399,518	Sum Lines 4 and 5	(a)
7	Total Transmission Depreciation and Amortization Expense		$ 53,974,118			$ 42,559,825	Sum Lines 2, 3 and 6	(a)
8	**Amortization of Gain/Loss on Reacquired Debt**	II.C	$ 999,391	Plant	28.7026%	$ 286,851	FF1 Page 117.64(c) + FF1 Page 117.66(c)	(a)
9	**Transmission Related Amortization of ITC**	II.D	$ (1,310,106)	Plant	28.7026%	$ (376,034)	FF1 Page 114.19(c)	(a)
10	**Transmission Related Municipal Tax Expense**	II.E	$ 120,588,821	Plant	28.7026%	$ 34,612,127	FF1 Page 263.5(i)	(a)
11	**Transmission Related Payroll Tax Expense**	II.F	$ 12,412,619	W&S	12.8871%	$ 1,599,627	FF1 Page 263.10(i)	(a)
12	**Transmission Operation and Maintenance Expense**	II.G						
13	Operation Supervision & Engineering (560)		$ 5,674,265	Direct	100.0000%	5,674,265	FF1 Page 321.83(b)	(a)
14			-	Internal Costs		-	FF1 Page 321.84(b)	(a)
15	Load Dispatch - Reliability (561.1)		1,389,220	Internal Costs		1,389,220	FF1 Page 321.85(b)	(a)
16	Load Dispatch-Monitor and Operate Transmission System (561.2)		1,311,222	Internal Costs		1,311,222	FF1 Page 321.86(b)	(a)
17	Load Dispatch-Transmission Service and Scheduling (561.3)		570,681	Internal Costs		570,681	FF1 Page 321.87(b)	(a)
18	Scheduling, System Control and Dispatch Services (561.4)		12,155,295	External Costs		-	FF1 Page 321.88(b)	(a)
19	Reliability, Planning and Standards Development (561.5)		273,226	Internal Costs		21,719	FF1 Page 321.89(b)	(a)
20	Transmission Service Studies (561.6)		106	Internal Costs		106	FF1 Page 321.90(b)	(a)
21	Generation Interconnection Studies (561.7)		-	Internal Costs		-	FF1 Page 321.91(b)	(a)
22	Reliability, Planning and Standards Development Services (561.8)		53,935	External Costs		-	FF1 Page 321.92(b)	(a)
23	Station Expenses (562)		2,729,963	Direct	100.0000%	2,729,963	FF1 Page 321.93(b)	(a)
24	Overhead Lines Expenses (563)		4,327,839	Direct	100.0000%	4,327,839	FF1 Page 321.94(b)	(a)
25	Underground Lines Expenses (564)		636,122	Direct	100.0000%	636,122	FF1 Page 321.95(b)	(a)
26	Miscellaneous Transmission Expenses (566)		496,506	Direct	100.0000%	496,506	FF1 Page 321.97(b)	(a)
27	Rents (567)		14,755	Direct	100.0000%	14,755	Sheet 5 - Page 1 of 2, Line 3, col (d)	(a)
28	Transmission Maintenance (568 - 573)		7,927,155	Direct	100.0000%	7,927,155	FF1 Page 321.111(b)	(a)
29	Regional Market Expense (575-576)		424,648	External Costs	0.0000%	-	FF1 Page 322.131(b)	(a)
30	Total Transmission O&M Expense		$ 37,984,938			$ 25,099,553	Sum Lines 13 thru 29	
31	**Transmission Related A&G Expenses**	II.H						
32	Administrative and General Expenses	I.B	$ 145,329,829				FF1 Page 323.197(b)	(a)
33	Property Insurance (924)		(926,016)				FF1 Page 323.185(b)	(a)
34	Employee Pensions and Benefits (926)		(51,124,252)				FF1 Page 323.187(b)	(a)
35	Regulatory Commission Expenses (928)		(9,560,209)				FF1 Page 323.189(b)	(a)
36	General Advertising Expenses (930.1)		(32,018)				FF1 Page 323.191(b)	(a)
37	Miscellaneous General Expenses (930.2) - **Note 2**		(52,118)				FF1 Page 232.2.14(e)	(a)
38	Merger-Related Costs		-				FF1 Page 232.2.14(e)	(b)
39	Sub-Total	II.H.1	83,635,216	W&S	12.8871%	10,778,154	Sum Lines 32 thru 38	(b)
40	Property Insurance (924)	II.H.2	926,016	Plant	28.7026%	265,791	Line 33	(a)
41	Employee Pensions and Benefits (926) - **Note 1**	II.H.1	51,124,252	W&S	12.8871%	6,588,433	Line 34	(a)
42	Regulatory Commission Expenses (928)	II.H.3	9,560,209	Footnote	20.8403%	1,992,376	Line 50	(a)
43	Transmission Merger-Related Costs		10,517,524	Footnote	100.0000%	10,517,524	**Exhibit No. ES-201, Page 1 of 1, Ln.24 (H)**	(b)
44	Total Transmission Related A&G Expenses		$ 155,763,217			$ 30,142,278	Sum Lines 39 thru 42	(b)
45	Regulatory Commission Expenses (928)	II.H.3						(a)
46	Assessment Charged by the MA DPU		$ 6,712,589		0.0000%	$ -	FF1 Page 350.2(d)	(a)
47	Proportionate share of expenses of FERC Assessment Order No. 472		1,992,376	Direct	100.0000%	1,992,376	FF1 Page 350.6(d)	(a)
48	Legal Fees - Distribution		787,573		0.0000%	-	FF1 Page 350.8(d)	(a)
49	Minor items - Distribution		67,671		0.0000%	-	FF1 Page 350.10(d)	(a)
50	Total Regulatory Commission Expenses	II.H.3	$ 9,560,209		20.8403%	$ 1,992,376	Sum Lines 46 thru 49	(a)

Line	Description	Allocation Factor	Reference	Notes
51				
52	Direct Allocation (Direct)	100.0000%		(a)
53	Wages & Salaries Allocation (W&S)	12.8871%	Sheet 6, Line 6(c)	(a)
54	Plant Allocation (Plant)	28.7026%	Sheet 6, Line 14(c)	(a)

55 **Note 1**
56 Included in the Employee Pension and Benefits Expenses are costs related to Post Retirement Benefits other than Pension (PBOP). PBOP costs are determined by an independent actuary
57 as required by ASC 715. The PBOP expense included in Account 926 for 2014 was ($5,000,000) as compared to $4,600,000 in 2013; as shown on the FF1, page 323, footnote.
58 Applying the labor allocator to the total PBOP expense results in $(251,041) of PBOP expense being recovered through the LNS Tariff in 2014, as compared to $249,762 in the prior year.

Line		2014	2013		Notes
59	PBOP	$ (5,000,000)	$ 4,600,000	Page 323 line 187 footnote	(a)
60	Capitalized PBOP & Other impact adjustment	3,052,000	(1,866,000)	**Note 3**	(a)
61	Net PBOP in account 926	$ (1,948,000)	$ 2,734,000	Line 57 + Line 58	(a)
62	Wages & Salaries Allocation (W&S)	12.8871%	9.1354%	Sheet 6	(a)
63	LNS portion of PBOP	$ (251,041)	$ 249,762	Line 59 x Line 60	(a)

64 **Note 2 -** NSTAR Green Program costs are excludable for Transmission billing purposes. Reflects actual information per the Company's accounting records.
65 **Note 3** - Reflects actual information per the Company's accounting records. ;

Notes:
(a) **Source of information is the NSTAR Annual Informational Filing submitted to FERC on August 14, 2015 in Docket No. ER07-549 and ER09-1243.**
(b) **Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses**

Exhibit No. ES-219
Schedule 1

Summary of Impact on Category B Revenue Requirements under Attachment ES-I, Schedule 21-ES to ISO-NE OATT (1-year Amortization)

Eversource Energy Service Company

Eversource Energy Service Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Comparison Under Present and Changed Rates
Under Attachment ES-I (Formerly NU-I)
For the Calendar Year 2016

	(A)	(B)	(C)	(D) = (C) - (B)	(E) = (D) / (B)
Line	Description	Total NU Category B Revenue Requirements Present Rates in Attachment ES-I	Total NU Category B Revenue Requirements under Changed Rates in Attachment ES-I	Difference	% Difference
1	2016 Estimated Category B Revenue Requirement	$ 35,511,216 (1)	$ 36,682,612 (2)	$ 1,171,000 (3)	3.3%

Notes:
(1) Exhibit No. ES-219, Schedule 2, Page 1 of 26, Line 9(H)
(2) Exhibit No. ES-219, Schedule 3, Page 1 of 26, Line 9(H)
(3) In connection with the one-year amortization proposal (with the proposed effective date of June 1, 2016), Eversource is showing the revenue impact for the twelve-month period June 1, 2016 through May 31, 2017. Eversource is using revenue requirement calculations for the calendar year 2016 as an estimate for the twelve-month period beginning June 1, 2016. See Cooper Testimony Exhibit No. ES-200.

	2016	2017	Total
The amounts for each year are as follows:	$ 683,083.33	$ 487,916.67	$ 1,171,000

Exhibit No. ES-219
Schedule 2

Category B Revenue Requirements under the Present Rates

Eversource Energy Service Company

CL&P and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I) of the ISO-NE OATT
For the Calendar year 2016

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)=(C)+(D)+(E)+(F)+(G)
			CL&P				WMECO	
Line	Description	Reference	B-N	M-N	G-C	GSRP	GSRP	Total
1	2014 Actual Schedule 21-ES, Category B Rev. Req.		$ 19,230,913 (1)	$ 10,169,321 (2)	$ 4,297,973 (3)	$ 579,688 (4)	$ 1,233,321 (5)	$ 35,511,216
2	Estimated 2015 Plant Additions	(6)	$ -	$ -	$ -	$ -	$ -	$ -
3	Carrying Charge Factor (CCF)	(6)	0.00%	0.00%	0.00%	0.00%	0.00%	
4	2015 Incremental Estimated Schedule 21-ES, Cat. B Rev. Req.	Line 2 x 3	-	-	-	-	-	$ -
5	Total Estimated Schedule 21-ES, Cat. B Revenue Requirement for 2015	Line 1 + 4	$ 19,230,913	$ 10,169,321	$ 4,297,973	$ 579,688	$ 1,233,321	$ 35,511,216
6	Estimated 2016 Plant Additions	(6)	$ -	$ -	$ -	$ -	$ -	$ -
7	Carrying Charge Factor (CCF)	(6)	0.00%	0.00%	0.00%	0.00%	0.00%	
8	2016 Incremental Estimated Schedule 21-ES, Cat. B Rev. Req.	Line 6 x 7	-	-	-	-	-	$ -
9	Total Estimated Schedule 21-ES, Cat. B Revenue Requirement for 2016	Line 5 + 8	$ 19,230,913	$ 10,169,321	$ 4,297,973	$ 579,688	$ 1,233,321	$ 35,511,216

Notes:
(1) Exhibit No. ES-219, Schedule 2, Page 2 of 26, Line 21(B)
(2) Exhibit No. ES-219, Schedule 2, Page 7 of 26, Line 21(B)
(3) Exhibit No. ES-219, Schedule 2, Page 12 of 26, Line 21(B)
(4) Exhibit No. ES-219, Schedule 2, Page 17 of 26, Line 21(B)
(5) Exhibit No. ES-219, Schedule 2, Page 22 of 26, Line 21(B)
(6) These are no forecasted plant additions for Category B

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Bethel-Norwalk
Sheet 1a

Line	(A)	Attachment I Reference Section:	(B)	(C) Source	(D) Notes
	I. INVESTMENT BASE				
1	Transmission Plant	II(A)(1)(a)	125,258,704	Sheet 2, Line 5	(a)
2	Transmission Plant Held for Future Use	II(A)(1)(b)	-	Sheet 2, Line 6	(a)
3	Accumulated Depreciation	II(A)(1)(c)	23,816,817	Sheet 2, Line 11	(a)
4	Accumulated Deferred Income Taxes	II(A)(1)(d)	19,494,337	Sheet 2, Line 12	(a)
5	Loss On Reacquired Debt	II(A)(1)(e)	187,920	Sheet 2, Line 13	(a)
6	Net Investment (Line 1+2-3-4+5)		82,135,470		
7	Prepayments	II(A)(1)(f)	787,415	Sheet 2, Line 14	(a)
8	Materials & Supplies	II(A)(1)(g)	1,459,628	Sheet 2, Line 15	(a)
9	Cash Working Capital	II(A)(1)(h)	381,388	Sheet 2, Line 22	(b)
10	Total Investment Base (Line 6+7+8+9)		84,763,901		(b)
	II. REVENUE REQUIREMENTS				
11	Investment Return and Income Taxes	II(A)	10,946,427	Sheet 4a, Line 15(4)	(b)
12	Depreciation Expense	II(B)	3,051,146	Sheet 8, Line 5	(a)
13	Amortization of Loss on Reacquired Debt	II(C)	19,538	Sheet 8, Line 6	(a)
14	Investment Tax Credit	II(D)	(22,551)	Sheet 8, Line 7	(a)
15	Property Tax Expense	II(E)	1,802,271	Sheet 8, Line 8	(a)
16	Payroll Tax Expense	II(F)	13,032	Sheet 8, Line 21	(a)
17	Operation & Maintenance Expense	II(G)	1,529,404	Sheet 8, Line 29	(a)
18	Administrative & General Expense	II(H)	1,493,448	Sheet 8, Line 39	(b)
19	Support Expenses	II(I)	-		(a)
20	Transmission Related Taxes and Fees	II(J)	398,198	Sheet 8, Line 40	(a)
21	Total Revenue Requirements (Line 11 thru 20)		19,230,913		(b)

Note:
Investment Return and Income Taxes (line 11 above) was calculated based on the Total Investment Base at 11.07% ROE, plus the Localized Post-2003 PTF Transmission Base (lines 1-3-4) at the .67% capped Incremental ROE

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247. Provided this support because these balances will be revised under the changed rates.

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Bethel-Norwalk
Sheet 2

Line No.	(A)	(B) Trans. Related Average		(C) Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Transmission Plant							
1	Localized Transmission Plant					121,745,648	Sheet 3, Line 19	(a)
2	Transmission General Plant	102,812,641	Note 4				FF1 page 204 ln. 96, footnote	(a)
3	Less: Convex-related General Plant	15,870,872					Note 1	(a)
4	Subtotal: General Plant, net of Convex (line 2 - 3)	86,941,769		4.0407%	Note 2	3,513,056		(a)
5	Total (line 1+4)					125,258,704		(a)
6	Localized Transmission Plant Held for Future Use					-		(a)
	Transmission Accumulated Depreciation							
7	Localized Transmission Accum. Depreciation					22,912,990	Sheet 9, Line 56(I)	(a)
8	General Plant Accum. Depreciation	26,085,325	Note 4				FF1 page 219 ln. 28, footnote	(a)
9	Less: Convex-related General Plant Acc Depr	3,717,252					Note 1	(a)
10	Subtotal: General Plant A/D, net of Convex (line 8-9)	22,368,074		4.0407%	Note 2	903,827		(a)
11	Total (line 7+10)					23,816,817		(a)
12	Transmission Accumulated Deferred Taxes					19,494,337	Sheet 10, Line 111	(a)
13	Unam. Loss on Reacquired Debt (189)	12,599,425		1.4915%	Note 3	187,920	FF1 page 111 ln. 81	(a)
14	Transmission Prepayments (165)	19,487,085	Note 4	4.0407%	Note 2	787,415	FF1 page 110 ln. 57, footnote	(a)
15	Transmission Materials and Supplies	36,123,136		4.0407%	Note 2	1,459,628	FF1 page 227 ln. 8	(a)
	Cash Working Capital							
16	Localized Operation & Maintenance Expense					1,529,404	Sheet 8, Line 29	(a)
17	Localized Administrative & General Expense					1,493,448	Sheet 8, Line 39	(b)
18	Subtotal (line 16+17)					3,022,852		(b)
19	12.5% allowance					0.125	x 45 / 360	(a)
20	Total current Year End (line 18*19)					377,857		(b)
21	Prior Year End Cash Working Capital					384,919	Note 1	(a)
22	Average Cash Working Capital [(line 20+21)/2]					381,388		(b)

Note 1: Reflects actual information per Eversource's accounting records.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.

Notes:

(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247 Provided this support because these balances will be revised under the changed rates.

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Bethel-Norwalk
Sheet 4a

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559	Note 2	46.27%	5.36%	Note 2	2.48%		
2	PREFERRED STOCK	$ 116,842,775		2.14%	4.80%		0.10%	0.10%	
3	COMMON EQUITY	$ 2,820,159,065		51.59%	11.07%	Note 1	5.71%	5.71%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399		100.00%			8.29%	5.81%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 8.29% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) / (1 + Eq. AFUDC of Deprec. Exp. / 1 - Federal Income Tax Rate)) / Total Inv. Base)) * Federal Income Tax Rate)

Source: Line 4, Col. (5); Sheet 8, Line 7; Sheet 6, Line 1; Sheet 1, Line 10; Federal Corporate Tax Rate

6 = ((5.81% + (((22,551) + 93,235) / 84,763,901)) * 35.00%)
7 (1 - 35.00%) — Federal Corporate Tax Rate

8 = 3.1734%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) / (1 + Eq. AFUDC of Deprec. Exp. / 1 - State Income Tax Rate)) / Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)

Source: Line 4, Col. (5); Sheet 8, Line 7; Sheet 6, Line 1; Sheet 1, Line 10; Line 8, Col. (1); Connecticut Corporate Tax Rate

9 = ((5.81% + (((22,551) + 93,235) / 84,763,901) + 3.1734%) * 9.00%)
10 (1 - 9.00%) — Connecticut Corporate Tax Rate

11 = 0.8967%

12 (a)+(b)+(c) **Cost of Capital Rate** = 12.3601%

Line			
13	INVESTMENT BASE	84,763,901	Sheet 1, Line 10
14			
15	x Cost of Capital Rate	12.3601%	Line 12, Col. (1)
16	= Investment Return and Income Taxes	$ 10,476,903	

Total Investment Return and Income Taxes		
@11.07%	$ 10,476,903	Line 16, Col. (1)
@.67%	$ 469,524	Sheet 5a, Line 17
	$ 10,946,427	To Sheet 1a, Line 11

Note 1: ROE per FERC Order in Docket No. ER11-66 dated October 16, 2014.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes:

(1) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(2) Provided this support because the balance in "Total Inv. Base" will be revised under the Changed Rates

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Bethel-Norwalk

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559	Note 2	46.27%					
2	PREFERRED STOCK	$ 116,842,775		2.14%					
3	COMMON EQUITY	$ 2,820,159,065		51.59%	0.50%	Note 1	0.26%	0.26%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399		100.00%			0.26%	0.26%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.26% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate) Total Inv. Base)) * Federal Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Federal Corporate Tax Rate

6 = ((0.26% + ((0 + 0) / 84,763,901)) * 35.00%)
7 (1 - 35.00%) Federal Corporate Tax Rate

8 = 0.1400%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate) Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Line 8, Col. (1); Connecticut Corporate Tax Rate

9 = ((0.26% + ((0 + 0) / 84,763,901) + 0.1400%) * 9.00%)
10 (1 - 9.00%) Connecticut Corporate Tax Rate

11 = 0.0396%

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.4396%

13	INVESTMENT BASE	84,763,901	Line 16, Col. (4)
14	x Cost of Capital Rate	0.4396%	Line 12, Col. (1)
15	= Investment Return and Income Taxes	$ 372,622	to Sheet 4a, Line 14(4)

Note 1: CAP on ROE incentives per FERC Order in Docket No. EL11-66 dated March 3, 2015.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.

Notes:

(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-217, Schedule 1, Page 2 of 2, Line 12
(2) The balance in "Total Inv. Base" is revised under the Changed Rates

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Bethel-Norwalk
Sheet 8

Line No.	(A)	(B) Year End		(C) Localized Trans. Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Depreciation Expense							
1	Transmission Depreciation					2,894,776	Sheet 9, Line 58	(a)
2	General Depreciation	4,980,574	Note 4				FF1 page 336 ln. 10, footnote	(a)
3	*less:* Convex-related General Plant Depreciation Expense	1,110,693					Note 1	(a)
4	Subtotal: General Plant Depr Exp, net of Convex (line 2-3)	3,869,881		4.0407%	Note 2	156,370		(a)
5	Total (line 1+4)					3,051,146		(a)
6	Amortization of Loss on Reacquired Debt	1,309,927		1.4915%	Note 3	19,538	FF1 page 117 ln. 64	(a)
7	Amortization of Investment Tax Credits	1,511,975		1.4915%	Note 3	22,551	FF1 page 266 ln. 8 (f)	(a)
8	Property Taxes	120,836,131		1.4915%	Note 3	1,802,271	FF1 page 263 ln. 24i & 25i	(a)
	Payroll Tax Expense							
9	Federal Unemployment	5,226					FF1 page 262 ln. 3i, footnote	(a)
10	FICA	233,351					FF1 page 262 ln. 5i, footnote	(a)
11	Medicare	65,613					FF1 page 262 ln. 9i, footnote	(a)
12	CT Unemployment	16,786					FF1 page 262 ln. 15i, footnote	(a)
13	MA Unemployment	(285)					FF1 page 262 ln. 32i, footnote	(a)
14	MA Universal Health	64					FF1 page 262 ln. 33i, footnote	(a)
15	NH Unemployment	1,754					FF1 page 262.1 ln. 4i, footnote	(a)
16	NJ Unemployment	-					FF1 page 262 footnote	(a)
17	DC Unemployment	11					FF1 page 262.1 ln. 14i, footnote	(a)
18	FL Unemployment	1					FF1 page 262.1 ln. 18i, footnote	(a)
19	MI Unemployment	6					FF1 page 262.1 ln. 22i, footnote	(a)
20	NY Unemployment	-					FF1 page 262.1 ln. 10i, footnote	(a)
21	Total (Line 9 to 20)	322,527	Note 4	4.0407%	Note 2	13,032		
	Transmission Operation and Maintenance							
22	Operation and Maintenance	77,432,007					FF1 page 321 ln. 112	(a)
23	Transmission of Electricity by Others - #565	21,727,966					FF1 page 321 ln. 96	(a)
24	Load Dispatching - #561	-					FF1 page 321 ln. 84	(a)
25	Account 561.1	3,245,594					FF1 page 321 ln. 85	(a)
26	Account 561.2	5,212,556					FF1 page 321 ln. 86	(a)
27	Account 561.3	2,238,612					FF1 page 321 ln. 87	(a)
28	Account 561.4	7,157,291					FF1 page 321 ln. 88	(a)
29	O&M (line 22 - lines 23 to 28)	37,849,988		4.0407%	Note 2	1,529,404		(a)
	Transmission-related Administrative and General							
30	Administrative and General	37,202,294	Note 4				FF1 page 320 ln. 197 b, footnote	(a)
31	less: Property Insurance (#924)	763,857	Note 4				FF1 Page 320 ln. 185 b, footnote	(a)
32	less: Regulatory Commission Expenses (#928)	2,749,411	Note 4				FF1 page 320 ln. 189 b, footnote	(a)
33	less: General Advertising Expense (#930.1)	10,766	Note 4				FF1 page 320 ln. 191 b, footnote	(a)
34	Subtotal (line 30 - lines 31 to 33)	33,678,260		4.0407%	Note 2	1,360,837		(a)
35	plus: Property Insurance	1,413,419		1.4915%	Note 3	21,081	FF1 page 323 ln. 185	(a)
36	plus: Trans. Regulatory Comm. Exp.	2,749,411		4.0407%	Note 2	111,095	FF1 page 320 ln. 189 b, footnote	(a)
37	plus: Trans. Related General Advertising Expense	10,766		4.0407%	Note 2	435	FF1 page 320 ln. 191 b, footnote	(a)
38	plus: Trans. Related Public Education Expense	-				-	FF1 page 114 ln. 49, footnote	(a)
39	Total A&G (sum of lines 34 to 38)	37,851,856				1,493,448		(b)
40	Transmission Related Taxes and Fees	9,854,673		4.0407%	Note 2	398,198	Note 5	(a)

Note 1: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.
Note 5: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment B.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
Provided this support because these balances will be revised under the changed rates.

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Middletown-Norwalk
Sheet 1a

Line	(A)	Attachment I Reference Section:	(B)	(C) Source	(D) Notes
	I. INVESTMENT BASE				
1	Transmission Plant	II(A)(1)(a)	62,028,638	Sheet 2, Line 5	(a)
2	Transmission Plant Held for Future Use	II(A)(1)(b)	-	Sheet 2, Line 6	(a)
3	Accumulated Depreciation	II(A)(1)(c)	9,382,562	Sheet 2, Line 11	(a)
4	Accumulated Deferred Income Taxes	II(A)(1)(d)	7,626,580	Sheet 2, Line 12	(a)
5	Loss On Reacquired Debt	II(A)(1)(e)	93,059	Sheet 2, Line 13	(a)
6	Net Investment (Line 1+2-3-4+5)		45,112,555		
7	Prepayments	II(A)(1)(f)	389,937	Sheet 2, Line 14	(a)
8	Materials & Supplies	II(A)(1)(g)	722,824	Sheet 2, Line 15	(a)
9	Cash Working Capital	II(A)(1)(h)	188,956	Sheet 2, Line 22	(b)
10	Total Investment Base (Line 6+7+8+9)		46,414,272		(b)
	II. REVENUE REQUIREMENTS				
11	Investment Return and Income Taxes	II(A)	5,993,077	Sheet 4a, Line 15(4)	(b)
12	Depreciation Expense	II(B)	1,584,643	Sheet 8, Line 5	(a)
13	Amortization of Loss on Reacquired Debt	II(C)	9,675	Sheet 8, Line 6	(a)
14	Investment Tax Credit	II(D)	(11,167)	Sheet 8, Line 7	(a)
15	Property Tax Expense	II(E)	892,496	Sheet 8, Line 8	(a)
16	Payroll Tax Expense	II(F)	6,454	Sheet 8, Line 21	(a)
17	Operation & Maintenance Expense	II(G)	757,378	Sheet 8, Line 29	(a)
18	Administrative & General Expense	II(H)	739,573	Sheet 8, Line 39	(b)
19	Support Expenses	II(I)	-		(a)
20	Transmission Related Taxes and Fees	II(J)	197,192	Sheet 8, Line 40	(a)
21	Total Revenue Requirements (Line 11 thru 20)		10,169,321		(b)

Note:
Investment Return and Income Taxes (line 11 above) was calculated based on the Total Investment Base at 11.07% ROE, plus the Localized Post-2003 PTF Transmission Base (lines 1-3-4) at the .67% capped Incremental ROE.

Notes:

(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247

(b) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247. Provided this support because these balances will be revised under the changed rates.

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Middletown-Norwalk
Sheet 2

Line No.	(A)	(B) Trans. Related Average		(C) Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Transmission Plant							
1	Localized Transmission Plant					60,288,933	Sheet 3, Line 18	(a)
2	Transmission General Plant	102,812,641	Note 4				FF1 page 204 ln. 96, footnote	(a)
3	Less: Convex-related General Plant	15,870,872					Note 1	(a)
4	Subtotal: General Plant, net of Convex (line 2 - 3)	86,941,769		2.0010%	Note 2	1,739,705		(a)
5	Total (line 1+4)					62,028,638		(a)
6	Localized Transmission Plant Held for Future Use					-		(a)
	Transmission Accumulated Depreciation							
7	Localized Transmission Accum. Depreciation					8,934,977	Sheet 9, Line 84(I)	(a)
8	General Plant Accum. Depreciation	26,085,325	Note 4				FF1 page 219 ln. 28, footnote	(a)
9	Less: Convex-related General Plant Acc Depr	3,717,252					Note 1	(a)
10	Subtotal: General Plant A/D, net of Convex (line 8-9)	22,368,074		2.0010%	Note 2	447,585		(a)
11	Total (line 7+10)					9,382,562		(a)
12	Transmission Accumulated Deferred Taxes					7,626,580	Sheet 10, Line 105	(a)
13	Unam. Loss on Reacquired Debt (189)	12,599,425		0.7386%	Note 3	93,059	FF1 page 111 ln. 81	(a)
14	Transmission Prepayments (165)	19,487,085	Note 4	2.0010%	Note 2	389,937	FF1 page 110 ln. 57, footnote	(a)
15	Transmission Materials and Supplies	36,123,136		2.0010%	Note 2	722,824	FF1 page 227 ln. 8	(a)
	Cash Working Capital							
16	Localized Operation & Maintenance Expense					757,378	Sheet 8, Line 29	(a)
17	Localized Administrative & General Expense					739,573	Sheet 8, Line 39	(b)
18	Subtotal (line 16+17)					1,496,951		(b)
19	12.5% allowance					0.125	x 45 / 360	(a)
20	Total current Year End (line 18*19)					187,119		(b)
21	Prior Year End Cash Working Capital					190,793	Note 1	(a)
22	Average Cash Working Capital [(line 20+21)/2]					188,956		(b)

Note 1: Reflects actual information per Eversource's accounting records.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247 Provided this support because these balances will be revised under the changed rates.

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Middletown-Norwalk
Sheet 4a

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559	Note 2	46.27%	5.36%	Note 2	2.48%		
2	PREFERRED STOCK	$ 116,842,775		2.14%	4.80%		0.10%	0.10%	
3	COMMON EQUITY	$ 2,820,159,065		51.59%	11.07%	Note 1	5.71%	5.71%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399		100.00%			8.29%	5.81%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 8.29% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / Total Inv. Base)) * Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

Source: Line 4, Col. (5); Sheet 8, Line 7; Sheet 6, Line 1; Sheet 1, Line 10; Federal Corporate Tax Rate

6 = ((5.81% + (((11,167) + 46,171) / 46,414,272)) * 35.00%)
7 (1 - 35.00%) Federal Corporate Tax Rate

8 = 3.1691%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / Total Inv. Base) + Federal Income Tax) * State Income Tax Rate) / (1 - State Income Tax Rate)

Source: Line 4, Col. (5); Sheet 8, Line 7; Sheet 6, Line 1; Sheet 1, Line 10; Line 8, Col. (1); Connecticut Corporate Tax Rate

9 = ((5.81% + (((11,167) + 46,171) / 46,414,272) + 3.1691%) * 9.00%)
10 (1 - 9.00%) Connecticut Corporate Tax Rate

11 = 0.8955%

12 (a)+(b)+(c) **Cost of Capital Rate** = 12.3546%

13	INVESTMENT BASE	46,414,272	Sheet 1, Line 10
14			
15	x Cost of Capital Rate	12.3546%	Line 12, Col. (1)
16	= Investment Return and Income Taxes	$ 5,734,298	

Total Investment Return and Income Taxes		
@11.07%	$ 5,734,298	Line 16, Col. (1)
@.67%	$ 258,779	Sheet 5a, Line 17
	$ 5,993,077	To Sheet 1a, Line 11

Note 1: ROE per FERC Order in Docket No. ER11-66 dated October 16, 2014.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes:

(1) **Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247**
(2) **Provided this support because the balance in "Total Inv. Base" will be revised under the Changed Rates**

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Middletown-Norwalk
Sheet 5a

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL	(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559	Note 2	46.27%				
2	PREFERRED STOCK	$ 116,842,775		2.14%				
3	COMMON EQUITY	$ 2,820,159,065		51.59%	0.50% Note 1	0.26%	0.26%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399		100.00%		0.26%	0.26%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.26% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate)) / Total Inv. Base)) * Federal Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Federal Corporate Tax Rate

6 = ((0.26% + ((0 + 0) / Line 16, Col. (4) 46,414,272)) * 35.00%)

7 (1 - 35.00%) Federal Corporate Tax Rate

8 = 0.1400%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate)) / Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Line 8, Col. (1); Connecticut Corporate Tax Rate

9 = ((0.26% + ((0 + 0) / 46,414,272) + 0.1400%) * 9.00%)

10 (1 - 9.00%) Connecticut Corporate Tax Rate

11 = 0.0396%

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.4396%

13 INVESTMENT BASE 46,414,272 Line 16, Col. (4)

14 x Cost of Capital Rate 0.4396% Line 12, Col. (1)

15 = Investment Return and Income Taxes $ 204,037 to Sheet 4a, Line 14(4)

Note 1: CAP on ROE incentives per FERC Order in Docket No. EL11-66 dated March 3, 2015.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.

Notes:

(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-217, Schedule 1, Page 2 of 2, Line 12
(2) The balance in "Total Inv. Base" is revised under the Changed Rates

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Middletown-Norwalk
Sheet 8

Line No.	(A)	(B) Year End		(C) Localized Trans. Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Depreciation Expense							
1	Transmission Depreciation					1,507,207	Sheet 9, Line 86	(a)
2	General Depreciation	4,980,574	Note 4				FF1 page 336 ln. 10, footnote	(a)
3	*less:* Convex-related General Plant Depreciation Expense	1,110,693					Note 1	(a)
4	Subtotal: General Plant Depr Exp, net of Convex (line 2-3)	3,869,881		2.0010%	Note 2	77,436		(a)
5	Total (line 1+4)					1,584,643		(a)
6	Amortization of Loss on Reacquired Debt	1,309,927		0.7386%	Note 3	9,675	FF1 page 117 ln. 64	(a)
7	Amortization of Investment Tax Credits	1,511,975		0.7386%	Note 3	11,167	FF1 page 266 ln. 8 (f)	(a)
8	Property Taxes	120,836,131		0.7386%	Note 3	892,496	FF1 page 263 ln. 24i & 25i	(a)
	Payroll Tax Expense							
9	Federal Unemployment	5,226					FF1 page 262 ln. 3i, footnote	(a)
10	FICA	233,351					FF1 page 262 ln. 5i, footnote	(a)
11	Medicare	65,613					FF1 page 262 ln. 9i, footnote	(a)
12	CT Unemployment	16,786					FF1 page 262 ln. 15i, footnote	(a)
13	MA Unemployment	(285)					FF1 page 262 ln. 32i, footnote	(a)
14	MA Universal Health	64					FF1 page 262 ln. 33i, footnote	(a)
15	NH Unemployment	1,754					FF1 page 262.1 ln. 4i, footnote	(a)
16	NJ Unemployment	-					FF1 page 262 footnote	(a)
17	DC Unemployment	11					FF1 page 262.1 ln. 14i, footnote	(a)
18	FL Unemployment	1					FF1 page 262.1 ln. 18i, footnote	(a)
19	MI Unemployment	6					FF1 page 262.1 ln. 22i, footnote	(a)
20	NY Unemployment	-					FF1 page 262.1 ln. 10i, footnote	(a)
21	Total (Line 9 to 20)	322,527	Note 4	2.0010%	Note 2	6,454		(a)
	Transmission Operation and Maintenance							
22	Operation and Maintenance	77,432,007					FF1 page 321 ln. 112	(a)
23	Transmission of Electricity by Others - #565	21,727,966					FF1 page 321 ln. 96	(a)
24	Load Dispatching - #561	-					FF1 page 321 ln. 84	(a)
25	Account 561.1	3,245,594					FF1 page 321 ln. 85	(a)
26	Account 561.2	5,212,556					FF1 page 321 ln. 86	(a)
27	Account 561.3	2,238,612					FF1 page 321 ln. 87	(a)
28	Account 561.4	7,157,291					FF1 page 321 ln. 88	(a)
29	O&M (line 22 - lines 23 to 28)	37,849,988		2.0010%	Note 2	757,378		(a)
	Transmission-related Administrative and General							
30	Administrative and General	37,202,294	Note 4				FF1 page 320 ln. 197 b, footnote	(a)
31	**less:** Property Insurance (#924)	763,857	Note 4				FF1 Page 320 ln. 185 b, footnote	(a)
32	**less:** Regulatory Commission Expenses (#928)	2,749,411	Note 4				FF1 page 320 ln. 189 b, footnote	(a)
33	**less:** General Advertising Expense (#930.1)	10,766	Note 4				FF1 page 320 ln. 191 b, footnote	(a)
34	Subtotal (line 30 - lines 31 to 33)	33,678,260		2.0010%	Note 2	673,902		(a)
35	**plus:** Property Insurance	1,413,419		0.7386%	Note 3	10,440	FF1 page 323 ln. 185	(a)
36	**plus:** Trans. Regulatory Comm. Exp.	2,749,411		2.0010%	Note 2	55,016	FF1 page 320 ln. 189 b, footnote	(a)
37	**plus:** Trans. Related General Advertising Expense	10,766		2.0010%	Note 2	215	FF1 page 320 ln. 191 b, footnote	(a)
38	**plus:** Trans. Related Public Education Expense	-				-	FF1 page 114 ln. 49, footnote	(a)
39	Total A&G (sum of lines 34 to 38)	37,851,856				739,573		(b)
40	Transmission Related Taxes and Fees	9,854,673		2.0010%	Note 2	197,192	Note 5	(a)

Note 1: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.
Note 5: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment B.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247 Provided this support because these balances will be revised under the changed rates.

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Glenbrook Cables
Sheet 1a

Line	(A) I. INVESTMENT BASE	Attachment I Reference Section:	(B)	(C) Source	(D) Notes
1	Transmission Plant	II(A)(1)(a)	2,644,161	Sheet 2, Line 5	(a)
2	Transmission Plant Held for Future Use	II(A)(1)(b)	31,396,972	Sheet 2, Line 6	(a)
3	Accumulated Depreciation	II(A)(1)(c)	353,497	Sheet 2, Line 11	(a)
4	Accumulated Deferred Income Taxes	II(A)(1)(d)	323,209	Sheet 2, Line 12	(a)
5	Loss On Reacquired Debt	II(A)(1)(e)	3,969	Sheet 2, Line 13	(a)
6	Net Investment (Line 1+2-3-4+5)		33,368,396		
7	Prepayments	II(A)(1)(f)	16,622	Sheet 2, Line 14	(a)
8	Materials & Supplies	II(A)(1)(g)	30,813	Sheet 2, Line 15	(a)
9	Cash Working Capital	II(A)(1)(h)	8,056	Sheet 2, Line 22	(b)
10	Total Investment Base (Line 6+7+8+9)		33,423,887		(b)
	II. REVENUE REQUIREMENTS				
11	Investment Return and Income Taxes	II(A)	4,124,327	Sheet 4a, Line 15(4)	(b)
12	Depreciation Expense	II(B)	63,152	Sheet 8, Line 5	(a)
13	Amortization of Loss on Reacquired Debt	II(C)	413	Sheet 8, Line 6	(a)
14	Investment Tax Credit	II(D)	(476)	Sheet 8, Line 7	(a)
15	Property Tax Expense	II(E)	38,063	Sheet 8, Line 8	(a)
16	Payroll Tax Expense	II(F)	275	Sheet 8, Line 21	(a)
17	Operation & Maintenance Expense	II(G)	32,286	Sheet 8, Line 29	(a)
18	Administrative & General Expense	II(H)	31,527	Sheet 8, Line 39	(b)
19	Support Expenses	II(I)	-		(a)
20	Transmission Related Taxes and Fees	II(J)	8,406	Sheet 8, Line 40	(a)
21	Total Revenue Requirements (Line 11 thru 20)		4,297,973		(b)

Note:
Investment Return and Income Taxes (line 11 above) was calculated based on the Total Investment Base at 11.07% ROE, plus the Localized Post-2003 PTF Transmission Base (lines 1-3-4) at the .67% capped Incremental ROE.

Notes:

(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247

(b) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247. Provided this support because these balances will be revised under the changed rates.

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
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For Costs in 2014
Glenbrook Cables
Sheet 2

Line No.	(A)	(B) Trans. Related Average		(C) Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Transmission Plant							
1	Localized Transmission Plant					2,570,000	Sheet 3, Line 17	(a)
2	Transmission General Plant	102,812,641	Note 4				FF1 page 204 ln. 96, footnote	(a)
3	Less: Convex-related General Plant	15,870,872					Note 1	(a)
4	Subtotal: General Plant, net of Convex (line 2 - 3)	86,941,769		0.0853%	Note 2	74,161		(a)
5	Total (line 1+4)					2,644,161		(a)
6	Localized Transmission Plant Held for Future Use					31,396,972		(a)
	Transmission Accumulated Depreciation							
7	Localized Transmission Accum. Depreciation					334,418	Sheet 9, Line 17(I)	(a)
8	General Plant Accum. Depreciation	26,085,325	Note 4				FF1 page 219 ln. 28, footnote	(a)
9	Less: Convex-related General Plant Acc Depr	3,717,252					Note 1	(a)
10	Subtotal: General Plant A/D, net of Convex (line 8-9)	22,368,074		0.0853%	Note 2	19,080		(a)
11	Total (line 7+10)					353,497		(a)
12	Transmission Accumulated Deferred Taxes					323,209	Sheet 10, Line 32	(a)
13	Unam. Loss on Reacquired Debt (189)	12,599,425		0.0315%	Note 3	3,969	FF1 page 111 ln. 81	(a)
14	Transmission Prepayments (165)	19,487,085	Note 4	0.0853%	Note 2	16,622	FF1 page 110 ln. 57, footnote	(a)
15	Transmission Materials and Supplies	36,123,136		0.0853%	Note 2	30,813	FF1 page 227 ln. 8	(a)
	Cash Working Capital							
16	Localized Operation & Maintenance Expense					32,286	Sheet 8, Line 29	(a)
17	Localized Administrative & General Expense					31,527	Sheet 8, Line 39	(b)
18	Subtotal (line 16+17)					63,813		(b)
19	12.5% allowance					0.125	x 45 / 360	(a)
20	Total current Year End (line 18*19)					7,977		(b)
21	Prior Year End Cash Working Capital					8,135	Note 1	(a)
22	Average Cash Working Capital [(line 20+21)/2]					8,056		(b)

Note 1: Reflects actual information per Eversource's accounting records.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
Provided this support because these balances will be revised under the changed rates.

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
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Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Glenbrook Cables
Sheet 4a

Line No.		(1) 2014 AVERAGE CAPITALIZATION	(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL	(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559 Note 2	46.27%	5.36% Note 2	2.48%		
2	PREFERRED STOCK	$ 116,842,775	2.14%	4.80%	0.10%	0.10%	
3	COMMON EQUITY	$ 2,820,159,065	51.59%	11.07% Note 1	5.71%	5.71%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399	100.00%		8.29%	5.81%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 8.29% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate)) / Total Inv. Base)) * Federal Income Tax Rate)

Source: Line 4, Col. (5); Sheet 8, Line 7; Sheet 6, Line 1; Sheet 1, Line 10; Federal Corporate Tax Rate

6 = ((5.81% + (((476) + 1,968) / 33,423,887)) * 35.00%)
7 (1 - 35.00%) Federal Corporate Tax Rate

8 = 3.1309%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate)) / Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)

Source: Line 4, Col. (5); Sheet 8, Line 7; Sheet 6, Line 1; Sheet 1, Line 10; Line 8, Col. (1); Connecticut Corporate Tax Rate

9 = ((5.81% + (((476) + 1,968) / 33,423,887) + 3.1309%) * 9.00%)
10 (1 - 9.00%) Connecticut Corporate Tax Rate

11 = 0.8847%

12 (a)+(b)+(c) **Cost of Capital Rate** = 12.3056%

13	INVESTMENT BASE	33,423,887	Sheet 1, Line 10
14			
15	x Cost of Capital Rate	12.3056%	Line 12, Col. (1)
16	= Investment Return and Income Taxes	$ 4,113,010	

Total Investment Return and Income Taxes		
@11.07%	$ 4,113,010	Line 16, Col. (1)
@.67%	$ 11,317	Sheet 5a, Line 17
	$ 4,124,327	To Sheet 1a, Line 11

Note 1: ROE per FERC Order in Docket No. ER11-66 dated October 16, 2014.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes:

(1) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(2) Provided this support because the balance in "Total Inv. Base" will be revised under the Changed Rates

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
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Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
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Glenbrook Cables

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559	Note 2	46.27%					
2	PREFERRED STOCK	$ 116,842,775		2.14%					
3	COMMON EQUITY	$ 2,820,159,065		51.59%	0.50%	Note 1	0.26%	0.26%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399		100.00%			0.26%	0.26%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.26% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate)) / Total Inv. Base)) * Federal Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Federal Corporate Tax Rate

6 = ((0.26% + ((0 + 0) / 33,423,887)) * 35.00%)
7 (1 - 35.00%) Federal Corporate Tax Rate

8 = 0.1400%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate)) / Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Line 8, Col. (1); Connecticut Corporate Tax Rate

9 = ((0.26% + ((0 + 0) / 33,423,887) + 0.1400%) * 9.00%)
10 (1 - 9.00%) Connecticut Corporate Tax Rate

11 = 0.0396%

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.4396%

13	INVESTMENT BASE	33,423,887	Line 16, Col. (4)
14	x Cost of Capital Rate	0.4396%	Line 12, Col. (1)
15	= Investment Return and Income Taxes	$ 146,931	to Sheet 4a, Line 14(4)

Note 1: CAP on ROE incentives per FERC Order in Docket No. EL11-66 dated March 3, 2015.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.

Notes:
(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-217, Schedule 1, Page 2 of 2, Line 12
(2) The balance in "Total Inv. Base" is revised under the Changed Rates

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Glenbrook Cables
Sheet 8

Line No.	(A)	(B) Year End		(C) Localized Trans. Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Depreciation Expense							
1	Transmission Depreciation					59,851	Sheet 9, Line 19	(a)
2	General Depreciation	4,980,574	Note 4				FF1 page 336 ln. 10, footnote	(a)
3	*less:* Convex-related General Plant Depreciation Expense	1,110,693					Note 1	(a)
4	Subtotal: General Plant Depr Exp, net of Convex (line 2-3)	3,869,881		0.0853%	Note 2	3,301		(a)
5	Total (line 1+4)					63,152		(a)
6	Amortization of Loss on Reacquired Debt	1,309,927		0.0315%	Note 3	413	FF1 page 117 ln. 64	(a)
7	Amortization of Investment Tax Credits	1,511,975		0.0315%	Note 3	476	FF1 page 266 ln. 8 (f)	(a)
8	Property Taxes	120,836,131		0.0315%	Note 3	38,063	FF1 page 263 ln. 24i & 25i	(a)
	Payroll Tax Expense							
9	Federal Unemployment	5,226					FF1 page 262 ln. 3i, footnote	(a)
10	FICA	233,351					FF1 page 262 ln. 5i, footnote	(a)
11	Medicare	65,613					FF1 page 262 ln. 9i, footnote	(a)
12	CT Unemployment	16,786					FF1 page 262 ln. 15i, footnote	(a)
13	MA Unemployment	(285)					FF1 page 262 ln. 32i, footnote	(a)
14	MA Universal Health	64					FF1 page 262 ln. 33i, footnote	(a)
15	NH Unemployment	1,754					FF1 page 262.1 ln. 4i, footnote	(a)
16	NJ Unemployment	-					FF1 page 262 footnote	(a)
17	DC Unemployment	11					FF1 page 262.1 ln. 14i, footnote	(a)
18	FL Unemployment	1					FF1 page 262.1 ln. 18i, footnote	(a)
19	MI Unemployment	6					FF1 page 262.1 ln. 22i, footnote	(a)
20	NY Unemployment	-					FF1 page 262.1 ln. 10i, footnote	(a)
21	Total (Line 9 to 20)	322,527	Note 4	0.0853%	Note 2	275		(a)
	Transmission Operation and Maintenance							
22	Operation and Maintenance	77,432,007					FF1 page 321 ln. 112	(a)
23	Transmission of Electricity by Others - #565	21,727,966					FF1 page 321 ln. 96	(a)
24	Load Dispatching - #561	-					FF1 page 321 ln. 84	(a)
25	Account 561.1	3,245,594					FF1 page 321 ln. 85	(a)
26	Account 561.2	5,212,556					FF1 page 321 ln. 86	(a)
27	Account 561.3	2,238,612					FF1 page 321 ln. 87	(a)
28	Account 561.4	7,157,291					FF1 page 321 ln. 88	(a)
29	O&M (line 22 - lines 23 to 28)	37,849,988		0.0853%	Note 2	32,286		(a)
	Transmission-related Administrative and General							
30	Administrative and General	37,202,294	Note 4				FF1 page 320 ln. 197 b, footnote	(a)
31	less: Property Insurance (#924)	763,857	Note 4				FF1 Page 320 ln. 185 b, footnote	(a)
32	less: Regulatory Commission Expenses (#928)	2,749,411	Note 4				FF1 page 320 ln. 189 b, footnote	(a)
33	less: General Advertising Expense (#930.1)	10,766	Note 4				FF1 page 320 ln. 191 b, footnote	(a)
34	Subtotal (line 30 - lines 31 to 33)	33,678,260		0.0853%	Note 2	28,728		(a)
35	plus: Property Insurance	1,413,419		0.0315%	Note 3	445	FF1 page 323 ln. 185	(a)
36	plus: Trans. Regulatory Comm. Exp.	2,749,411		0.0853%	Note 2	2,345	FF1 page 320 ln. 189 b, footnote	(a)
37	plus: Trans. Related General Advertising Expense	10,766		0.0853%	Note 2	9	FF1 page 320 ln. 191 b, footnote	(a)
38	plus: Trans. Related Public Education Expense	-				-	FF1 page 114 ln. 49, footnote	(a)
39	Total A&G (sum of lines 34 to 38)	37,851,856				31,527		(b)
40	Transmission Related Taxes and Fees	9,854,673		0.0853%	Note 2	8,406	Note 5	(a)

Note 1: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.
Note 5: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment B.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247 Provided this support because these balances will be revised under the changed rates.

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 1a

Line	(A)	Attachment I Reference Section:	(B)	(C) Source	(D) Notes
	I. INVESTMENT BASE				
1	Transmission Plant	II(A)(1)(a)	3,169,795	Sheet 2, Line 5	(a)
2	Transmission Plant Held for Future Use	II(A)(1)(b)	-	Sheet 2, Line 6	(a)
3	Accumulated Depreciation	II(A)(1)(c)	116,694	Sheet 2, Line 11	(a)
4	Accumulated Deferred Income Taxes	II(A)(1)(d)	265,445	Sheet 2, Line 12	(a)
5	Loss On Reacquired Debt	II(A)(1)(e)	4,750	Sheet 2, Line 13	(a)
6	Net Investment (Line 1+2-3-4+5)		2,792,406		
7	Prepayments	II(A)(1)(f)	19,935	Sheet 2, Line 14	(a)
8	Materials & Supplies	II(A)(1)(g)	36,954	Sheet 2, Line 15	(a)
9	Cash Working Capital	II(A)(1)(h)	4,783	Sheet 2, Line 22	(b)
10	Total Investment Base (Line 6+7+8+9)		2,854,078		(b)
	II. REVENUE REQUIREMENTS				
11	Investment Return and Income Taxes	II(A)	368,465	Sheet 4a, Line 15(4)	(b)
12	Depreciation Expense	II(B)	78,802	Sheet 8, Line 5	(a)
13	Amortization of Loss on Reacquired Debt	II(C)	494	Sheet 8, Line 6	(a)
14	Investment Tax Credit	II(D)	(570)	Sheet 8, Line 7	(a)
15	Property Tax Expense	II(E)	45,555	Sheet 8, Line 8	(a)
16	Payroll Tax Expense	II(F)	330	Sheet 8, Line 21	(a)
17	Operation & Maintenance Expense	II(G)	38,721	Sheet 8, Line 29	(a)
18	Administrative & General Expense	II(H)	37,810	Sheet 8, Line 39	(b)
19	Support Expenses	II(I)	-		(a)
20	Transmission Related Taxes and Fees	II(J)	10,081	Sheet 8, Line 40	(a)
21	Total Revenue Requirements (Line 11 thru 20)		579,688		(b)

Note:
Investment Return and Income Taxes (line 11 above) was calculated based on the Total Investment Base at 11.07% ROE, plus the Localized PTF Transmission Base (lines 1-3-4) at the .67% capped Incremental ROE.

Notes:

(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247

(b) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247. Provided this support because these balances will be revised under the changed rates.

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
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Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 2

Line No.	(A)	(B) Trans. Related Average		(C) Allocation Factor		(D) Allocated to Localized	(E) Source		(F) Notes
	Transmission Plant								
1	Localized Transmission Plant					3,080,854	Sheet 3, Line 18	(a)	
2	Transmission General Plant	102,812,641	Note 4				FF1 page 204 ln. 96, footnote	(a)	
3	Less: Convex-related General Plant	15,870,872					Note 1	(a)	
4	Subtotal: General Plant, net of Convex (line 2 - 3)	86,941,769		0.1023%	Note 2	88,941		(a)	
5	Total (line 1+4)					3,169,795		(a)	
6	Localized Transmission Plant Held for Future Use					-		(a)	
	Transmission Accumulated Depreciation								
7	Localized Transmission Accum. Depreciation					93,811	Sheet 9, Line 10(I)	(a)	
8	General Plant Accum. Depreciation	26,085,325	Note 4				FF1 page 219 ln. 28, footnote	(a)	
9	Less: Convex-related General Plant Acc Depr	3,717,252					Note 1	(a)	
10	Subtotal: General Plant A/D, net of Convex (line 8-9)	22,368,074		0.1023%	Note 2	22,883		(a)	
11	Total (line 7+10)					116,694		(a)	
12	Transmission Accumulated Deferred Taxes					265,445	Sheet 10, Line 46	(a)	
13	Unam. Loss on Reacquired Debt (189)	12,599,425		0.0377%	Note 3	4,750	FF1 page 111 ln. 81	(a)	
14	Transmission Prepayments (165)	19,487,085	Note 4	0.1023%	Note 2	19,935	FF1 page 110 ln. 57, footnote	(a)	
15	Transmission Materials and Supplies	36,123,136		0.1023%	Note 2	36,954	FF1 page 227 ln. 8	(a)	
	Cash Working Capital								
16	Localized Operation & Maintenance Expense					38,721	Sheet 8, Line 29	(a)	
17	Localized Administrative & General Expense					37,810	Sheet 8, Line 39	(b)	
18	Subtotal (line 16+17)					76,531		(b)	
19	12.5% allowance					0.125	x 45 / 360	(a)	
20	Total current Year End (line 18*19)					9,566		(b)	
21	Prior Year End Cash Working Capital					-	Note 1	(a)	
22	Average Cash Working Capital [(line 20+21)/2]					4,783		(b)	

Note 1: Reflects actual information per Eversource's accounting records.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247 Provided this support because these balances will be revised under the changed rates.

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
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Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 4a

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559	Note 2	46.27%	5.36%	Note 2	2.48%		
2	PREFERRED STOCK	$ 116,842,775		2.14%	4.80%		0.10%	0.10%	
3	COMMON EQUITY	$ 2,820,159,065		51.59%	11.07%	Note 1	5.71%	5.71%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399		100.00%			8.29%	5.81%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 8.29% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / Total Inv. Base)) * Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

Source: Line 4, Col. (5); Sheet 8, Line 7; Sheet 6, Line 1; Sheet 1, Line 10; Federal Corporate Tax Rate

6 = ((5.81% + (((570) + 2,360) / 2,854,078)) * 35.00%)
7 (1 - 35.00%) Federal Corporate Tax Rate

8 = 3.1622%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / Total Inv. Base) + Federal Income Tax) * State Income Tax Rate) / (1 - State Income Tax Rate)

Source: Line 4, Col. (5); Sheet 8, Line 7; Sheet 6, Line 1; Sheet 1, Line 10; Line 8, Col. (1); Connecticut Corporate Tax Rate

9 = ((5.81% + (((570) + 2,360) / 2,854,078) + 3.1622%) * 9.00%)
10 (1 - 9.00%) Connecticut Corporate Tax Rate

11 = 0.8936%

12 (a)+(b)+(c) **Cost of Capital Rate** = 12.3458%

Line			
13	INVESTMENT BASE	2,854,078	Sheet 1, Line 10
14			
15	x Cost of Capital Rate	12.3458%	Line 12, Col. (1)
16	= Investment Return and Income Taxes	$ 352,359	

Total Investment Return and Income Taxes			
@11.07%	$	352,359	Line 16, Col. (1)
@.67%	$	16,106	Sheet 5a, Line 17
	$	368,465	To Sheet 1a, Line 11

Note 1: ROE per FERC Order in Docket No. ER11-66 dated October 16, 2014.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes:

(1) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(2) Provided this support because the balance in "Total Inv. Base" will be revised under the Changed Rates

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 5a

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559	Note 2	46.27%					
2	PREFERRED STOCK	$ 116,842,775		2.14%					
3	COMMON EQUITY	$ 2,820,159,065		51.59%	0.50%	Note 1	0.26%	0.26%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399		100.00%			0.26%	0.26%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.26% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate)) / Total Inv. Base)) * Federal Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Federal Corporate Tax Rate

6 = ((0.26% + ((0 + 0) / 2,854,078)) * 35.00%)
7 (1 - 35.00%) Federal Corporate Tax Rate

8 = 0.1400%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate)) / Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Line 8, Col. (1); Connecticut Corporate Tax Rate

9 = ((0.26% + ((0 + 0) / 2,854,078) + 0.1400%) * 9.00%)
10 (1 - 9.00%) Connecticut Corporate Tax Rate

11 = 0.0396%

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.4396%

13 INVESTMENT BASE 2,854,078 Line 16, Col. (4)

14 x Cost of Capital Rate 0.4396% Line 12, Col. (1)

15 = Investment Return and Income Taxes $ 12,547 to Sheet 4a, Line 14(4)

Note 1: CAP on ROE incentives per FERC Order in Docket No. EL11-66 dated March 3, 2015.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.

Notes:

(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-217, Schedule 1, Page 2 of 2, Line 12
(2) The balance in "Total Inv. Base" is revised under the Changed Rates

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 8

Line No.	(A)	(B) Year End		(C) Localized Trans. Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Depreciation Expense							
1	Transmission Depreciation					74,843	Sheet 9, Line 12	(a)
2	General Depreciation	4,980,574	Note 4				FF1 page 336 ln. 10, footnote	(a)
3	*less:* Convex-related General Plant Depreciation Expense	1,110,693					Note 1	(a)
4	Subtotal: General Plant Depr Exp, net of Convex (line 2-3)	3,869,881		0.1023%	Note 2	3,959		(a)
5	Total (line 1+4)					78,802		(a)
6	Amortization of Loss on Reacquired Debt	1,309,927		0.0377%	Note 3	494	FF1 page 117 ln. 64	(a)
7	Amortization of Investment Tax Credits	1,511,975		0.0377%	Note 3	570	FF1 page 266 ln. 8 (f)	(a)
8	Property Taxes	120,836,131		0.0377%	Note 3	45,555	FF1 page 263 ln. 24i & 25i	(a)
	Payroll Tax Expense							
9	Federal Unemployment	5,226					FF1 page 262 ln. 3i, footnote	(a)
10	FICA	233,351					FF1 page 262 ln. 5i, footnote	(a)
11	Medicare	65,613					FF1 page 262 ln. 9i, footnote	(a)
12	CT Unemployment	16,786					FF1 page 262 ln. 15i, footnote	(a)
13	MA Unemployment	(285)					FF1 page 262 ln. 32i, footnote	(a)
14	MA Universal Health	64					FF1 page 262 ln. 33i, footnote	(a)
15	NH Unemployment	1,754					FF1 page 262.1 ln. 4i, footnote	(a)
16	NJ Unemployment	-					FF1 page 262 footnote	(a)
17	DC Unemployment	11					FF1 page 262.1 ln. 14i, footnote	(a)
18	FL Unemployment	1					FF1 page 262.1 ln. 18i, footnote	(a)
19	MI Unemployment	6					FF1 page 262.1 ln. 22i, footnote	(a)
20	NY Unemployment	-					FF1 page 262.1 ln. 10i, footnote	(a)
21	Total (Line 9 to 20)	322,527	Note 4	0.1023%	Note 2	330		(a)
	Transmission Operation and Maintenance							
22	Operation and Maintenance	77,432,007					FF1 page 321 ln. 112	(a)
23	Transmission of Electricity by Others - #565	21,727,966					FF1 page 321 ln. 96	(a)
24	Load Dispatching - #561	-					FF1 page 321 ln. 84	(a)
25	Account 561.1	3,245,594					FF1 page 321 ln. 85	(a)
26	Account 561.2	5,212,556					FF1 page 321 ln. 86	(a)
27	Account 561.3	2,238,612					FF1 page 321 ln. 87	(a)
28	Account 561.4	7,157,291					FF1 page 321 ln. 88	(a)
29	O&M (line 22 - lines 23 to 28)	37,849,988		0.1023%	Note 2	38,721		(a)
	Transmission-related Administrative and General							
30	Administrative and General	37,202,294	Note 4				FF1 page 320 ln. 197 b, footnote	(a)
31	**less:** Property Insurance (#924)	763,857	Note 4				FF1 Page 320 ln. 185 b, footnote	(a)
32	**less:** Regulatory Commission Expenses (#928)	2,749,411	Note 4				FF1 page 320 ln. 189 b, footnote	(a)
33	**less:** General Advertising Expense (#930.1)	10,766	Note 4				FF1 page 320 ln. 191 b, footnote	(a)
34	Subtotal (line 30 - lines 31 to 33)	33,678,260		0.1023%	Note 2	34,453		(a)
35	**plus:** Property Insurance	1,413,419		0.0377%	Note 3	533	FF1 page 323 ln. 185	(a)
36	**plus:** Trans. Regulatory Comm. Exp.	2,749,411		0.1023%	Note 2	2,813	FF1 page 320 ln. 189 b, footnote	(a)
37	**plus:** Trans. Related General Advertising Expense	10,766		0.1023%	Note 2	11	FF1 page 320 ln. 191 b, footnote	(a)
38	**plus:** Trans. Related Public Education Expense	-				-	FF1 page 114 ln. 49, footnote	(a)
39	Total A&G (sum of lines 34 to 38)	37,851,856				37,810		(b)
40	Transmission Related Taxes and Fees	9,854,673		0.1023%	Note 2	10,081	Note 5	(a)

Note 1: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.
Note 5: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment B.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247 Provided this support because these balances will be revised under the changed rates.

Western Massachusetts Electric Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 1a

Line	(A)	Attachment I Reference Section:	(B)	(C) Source	(D) Notes
	I. INVESTMENT BASE				
1	Transmission Plant	II(A)(1)(a)	7,316,798	Sheet 2, Line 5	(a)
2	Transmission Plant Held for Future Use	II(A)(1)(b)	-	Sheet 2, Line 6	(a)
3	Accumulated Depreciation	II(A)(1)(c)	290,421	Sheet 2, Line 11	(a)
4	Accumulated Deferred Income Taxes	II(A)(1)(d)	603,776	Sheet 2, Line 12	(a)
5	Loss On Reacquired Debt	II(A)(1)(e)	2,313	Sheet 2, Line 13	(a)
6	Net Investment (Line 1+2-3-4+5)		6,424,914		
7	Prepayments	II(A)(1)(f)	5,502	Sheet 2, Line 14	(a)
8	Materials & Supplies	II(A)(1)(g)	26,259	Sheet 2, Line 15	(a)
9	Cash Working Capital	II(A)(1)(h)	7,721	Sheet 2, Line 22	(b)
10	Total Investment Base (Line 6+7+8+9)		6,464,396		(b)
	II. REVENUE REQUIREMENTS				
11	Investment Return and Income Taxes	II(A)	779,406	Sheet 4a, Line 15(4)	(b)
12	Depreciation Expense	II(B)	184,929	Sheet 8, Line 5	(a)
13	Amortization of Loss on Reacquired Debt	II(C)	323	Sheet 8, Line 6	(a)
14	Investment Tax Credit	II(D)	(154)	Sheet 8, Line 7	(a)
15	Property Tax Expense	II(E)	144,952	Sheet 8, Line 8	(a)
16	Payroll Tax Expense	II(F)	157	Sheet 8, Line 21	(a)
17	Operation & Maintenance Expense	II(G)	54,519	Sheet 8, Line 29	(a)
18	Administrative & General Expense	II(H)	69,012	Sheet 8, Line 39	(b)
19	Support Expenses	II(I)	-		(a)
20	Transmission Related Taxes and Fees	II(J)	177	Sheet 8, Line 40	(a)
21	Total Revenue Requirements (Line 11 thru 20)		1,233,321		(b)

Note:
Investment Return and Income Taxes (line 11 above) was calculated based on the Total Investment Base at 11.07% ROE, plus the Localized PTF Transmission Base (lines 1-3-4) at the .67% capped Incremental ROE.

Notes:

(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247

(b) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247. Provided this support because these balances will be revised under the changed rates.

Western Massachusetts Electric Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 2

Line No.	(A)	(B) Trans. Related Average		(C) Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Transmission Plant							
1	Localized Transmission Plant					7,159,714	Sheet 3, Line 33	(a)
2	Transmission General Plant	18,348,753	Note 4	0.8561%	Note 2	157,084	FF1 page 204 ln. 96, footnote	(a)
3	Total (line 1+2)					7,316,798		(a)
4	Localized Transmission Plant Held for Future Use					-		(a)
	Transmission Accumulated Depreciation							
5	Localized Transmission Accum. Depreciation					256,419	Sheet 9, Line 27(I)	(a)
6	General Plant Accum.Depreciation	3,971,742	Note 4	0.8561%	Note 2	34,002	FF1 page 219 ln. 28, footnote	(a)
7	Total (line 5+6)					290,421		(a)
8								
9	Transmission Accumulated Deferred Taxes					603,776	Sheet 10, Line 46	(a)
10	Unam. Loss on Reacquired Debt (189)	533,928		0.4332%	Note 3	2,313	FF1 page 111 ln. 81	(a)
11	Transmission Prepayments (165)	642,737	Note 4	0.8561%	Note 2	5,502	FF1 page 110 ln. 57, footnote	(a)
12	Transmission Materials and Supplies	3,067,304		0.8561%	Note 2	26,259	FF1 page 227 ln. 8	(a)
	Cash Working Capital							
13	Localized Operation & Maintenance Expense					54,519	Sheet 8, Line 28	(a)
14	Localized Administrative & General Expense					69,012	Sheet 8, Line 38	(b)
15	Subtotal (line 13+14)					123,531		(b)
16	12.5% allowance					0.125	x 45 / 360	(a)
17	Total current Year End (line 15*16)					15,441		(b)
18	Prior Year End Cash Working Capital					-		(a)
19	Average Cash Working Capital [(line 17+18)/2]					7,721		(b)

Note 1: Reflects actual information per Eversource's accounting records.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247 Provided this support because these balances will be revised under the changed rates.

Western Massachusetts Electric Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 4a

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 568,072,183	Note 2	49.54%	4.31%	Note 2	2.14%		
2	PREFERRED STOCK	$ -		0.00%	0.00%		0.00%	0.00%	
3	COMMON EQUITY	$ 578,634,319		50.46%	11.07%	Note 1	5.59%	5.59%	
4	TOTAL INVESTMENT RETURN	$ 1,146,706,502		100.00%			7.73%	5.59%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 7.73% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate)) / Total Inv. Base)) * Federal Income Tax Rate)

Source: Line 4, Col. (5); Sheet 8, Line 7; Sheet 6, Line 1; Sheet 1, Line 10; Federal Corporate Tax Rate

6 = ((5.59% + (((154) + 1,593) / Total Inv. Base 6,464,396)) * 35.00%)
7 (1 - 35.00%) Federal Corporate Tax Rate
8 = 3.0220%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate)) / Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)

Source: Line 4, Col. (5); Sheet 8, Line 7; Sheet 6, Line 1; Sheet 1, Line 10; Line 8, Col. (1); Massachusetts Corporate Tax Rate

9 = ((5.59% + (((154) + 1,593) / 6,464,396) + 3.0220%) * 8.00%)
10 (1 - 8.00%) Massachusetts Corporate Tax Rate
11 = 0.7508%

12 (a)+(b)+(c) **Cost of Capital Rate** = 11.5028%

13 INVESTMENT BASE 6,464,396 Sheet 1, Line 10
14
15 x Cost of Capital Rate 11.5028% Line 12, Col. (1)
16 = Investment Return and Income Taxes $ 743,587

Total Investment Return and Income Taxes			
@11.07%	$	743,587	Line 16, Col. (1)
@.67%	$	35,819	Sheet 5, Line 17
	$	779,406	To Sheet 1a, Line 11

Note 1: ROE per FERC Order in Docket No. ER04-157 dated March 24, 2008.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes:

(1) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(2) Provided this support because the balance in "Total Inv. Base" will be revised under the Changed Rates

Western Massachusetts Electric Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project

Line No.		(1) 2014 AVERAGE CAPITALIZATION	(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL	(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 568,072,183 Note 2	49.54%				
2	PREFERRED STOCK	$ -	0.00%				
3	COMMON EQUITY	$ 578,634,319	50.46%	0.50% Note 1	0.25%	0.25%	
4	TOTAL INVESTMENT RETURN	$ 1,146,706,502	100.00%		0.25%	0.25%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.25% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate)) / Total Inv. Base)) * Federal Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Federal Corporate Tax Rate

6 = ((0.25% + ((0 + 0) / 6,464,396)) * 35.00%)
7 (1 - 35.00%) Federal Corporate Tax Rate

8 = 0.1346%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate)) / Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Line 8, Col. (1); Massachusetts Corporate Tax Rate

9 = ((0.25% + ((0 + 0) / 6,464,396) + 0.1346%) * 8.00%)
10 (1 - 8.00%) Massachusetts Corporate Tax Rate

11 = 0.0334%

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.4180%

13 INVESTMENT BASE 6,464,396 Line 16, Col. (4)

14 x Cost of Capital Rate 0.4180% Line 12, Col. (1)

15 = Investment Return and Income Taxes $ 27,021 to Sheet 4a, Line 14(4)

Note 1: CAP on ROE incentives per FERC Order in Docket No. EL11-66 dated March 3, 2015.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.

Notes:

(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-217, Schedule 1, Page 2 of 2, Line 12
(2) The balance in "Total Inv. Base" is revised under the Changed Rates

Western Massachusetts Electric Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 8

Line No.	(A)	(B) Year End		(C) Localized Trans. Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Depreciation Expense							
1	Transmission Depreciation					178,169	Sheet 9, Line 29	(a)
2	General Depreciation	789,658	Note 4	0.8561%	Note 2	6,760	FF1 page 336 ln. 10, footnote	(a)
3	Total (line 1+4)					184,929		(a)
4								
5	Amortization of Loss on Reacquired Debt	74,501		0.4332%	Note 3	323	FF1 pg 117 ln. 64	(a)
6	Amortization of Investment Tax Credits	35,604		0.4332%	Note 3	154	FF1 page 266 ln. 8(f), footnote	(a)
7	Property Taxes	33,460,690		0.4332%	Note 3	144,952	FF1 page 263 ln. 31i & 32i	(a)
	Payroll Tax Expense							
8	Federal Unemployment	283					FF1 page 262 ln. 3i, footnote	(a)
9	FICA	13,202					FF1 page 262 ln. 5i, footnote	(a)
10	Medicare	3,757					FF1 page 262 ln. 9i, footnote	(a)
11	CT Unemployment	852					FF1 page 262 ln. 13i, footnote	(a)
12	MA Unemployment	69					FF1 page 262 ln. 22i, footnote	(a)
13	MA Universal Health	19					FF1 page 262 ln. 27i, footnote	(a)
14	NH Unemployment	108					FF1 page 262 ln. 37i, footnote	(a)
15	NJ Unemployment	-					FF1 page 262, footnote	(a)
16	DC Unemployment	1					FF1 page 262.1 ln. 6i, footnote	(a)
17	FL Unemployment	-					FF1 page 262, footnote	(a)
18	MI Unemployment	-					FF1 page 262, footnote	(a)
19	NY Unemployment	-					FF1 page 262, footnote	(a)
20	Total (Line 9 to 20)	18,291	Note 4	0.8561%	Note 2	157		
	Transmission Operation and Maintenance							
21	Operation and Maintenance	20,725,279					FF1 page 321 ln. 112	(a)
22	Transmission of Electricity by Others - #565	13,174,678					FF1 page 321 ln. 96	(a)
23	Load Dispatching - #561	-					FF1 page 321 ln. 84	(a)
24	Account 561.1	12,368					FF1 page 321 ln. 85	(a)
25	Account 561.2	50,569					FF1 page 321 ln. 86	(a)
26	Account 561.3	13,262					FF1 page 321 ln. 87	(a)
27	Account 561.4	1,106,108					FF1 page 321 ln. 88	(a)
28	O&M (line 22 - lines 23 to 28)	6,368,294		0.8561%	Note 2	54,519		(a)
	Transmission-related Administrative and General							
29	Administrative and General	8,041,502	Note 4				FF1 page 320 ln. 197, footnote	(a)
30	less: Property Insurance (#924)	106,141	Note 4				FF1 Page 320 ln. 185 b, footnote	(a)
31	less: Regulatory Commission Expenses (#928)	563,123	Note 4				FF1 page 320 ln. 189 b, footnote	(a)
32	less: General Advertising Expense (#930.1)	2,857	Note 4				FF1 page 320 ln. 191 b, footnote	(a)
33	Subtotal (line 30 - lines 31 to 33)	7,369,381		0.8561%	Note 2	63,089		(a)
34	plus: Property Insurance	248,747		0.4332%	Note 3	1,078	FF1 page 323 ln. 185	(a)
35	plus: Trans. Regulatory Comm. Exp.	563,123		0.8561%	Note 2	4,821	FF1 page 320 ln. 189 b, footnote	(a)
36	plus: Trans. Related General Advertising Expense	2,857		0.8561%	Note 2	24	FF1 page 320 ln. 191 b, footnote	(a)
37	plus: Trans. Related Public Education Expense	-				-	FF1 page 114 ln. 49, footnote	(a)
38	Total A&G (sum of lines 34 to 38)	8,184,108				69,012		(b)
39	Transmission Related Taxes and Fees	20,627		0.8561%	Note 2	177	Note 5	(a)

Note 1: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.
Note 5: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment B.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247 Provided this support because these balances will be revised under the changed rates.

Exhibit No. ES-219
Schedule 3

Category B Revenue Requirements under the Changed Rates

Eversource Energy Service Company

CL&P and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I) of the ISO-NE OATT
For the Calendar year 2016

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)=(C)+(D)+(E)+(F)+(G)
			CL&P				WMECO	
Line	Description	Reference	B-N	M-N	G-C	GSRP	GSRP	Total
1	2014 Actual Schedule 21-ES, Category B Rev. Req.		$ 19,964,122 (1)	$ 10,532,455 (2)	$ 4,313,452 (3)	$ 598,253 (4)	$ 1,274,330 (5)	$ 36,682,612
2	Estimated 2015 Plant Additions	(6)	$ -	$ -	$ -	$ -	$ -	$ -
3	Carrying Charge Factor (CCF)	(6)	0.00%	0.00%	0.00%	0.00%	0.00%	
4	2015 Incremental Estimated Schedule 21-ES, Cat. B Rev. Req.	Line 2 x 3	-	-	-	-	-	$ -
5	Total Estimated Schedule 21-ES, Cat. B Revenue Requirement for 2015	Line 1 + 4	$ 19,964,122	$ 10,532,455	$ 4,313,452	$ 598,253	$ 1,274,330	$ 36,682,612
6	Estimated 2016 Plant Additions	(6)	$ -	$ -	$ -	$ -	$ -	$ -
7	Carrying Charge Factor (CCF)	(6)	0.00%	0.00%	0.00%	0.00%	0.00%	
8	2016 Incremental Estimated Schedule 21-ES, Cat. B Rev. Req.	Line 6 x 7	-	-	-	-	-	$ -
9	Total Estimated Schedule 21-ES, Cat. B Revenue Requirement for 2016	Line 5 + 8	$ 19,964,122	$ 10,532,455	$ 4,313,452	$ 598,253	$ 1,274,330	$ 36,682,612

Notes:
(1) Exhibit No. ES-219, Schedule 3, Page 2 of 26, Line 21(B)
(2) Exhibit No. ES-219, Schedule 3, Page 7 of 26, Line 21(B)
(3) Exhibit No. ES-219, Schedule 3, Page 12 of 26, Line 21(B)
(4) Exhibit No. ES-219, Schedule 3, Page 17 of 26, Line 21(B)
(5) Exhibit No. ES-219, Schedule 3, Page 22 of 26, Line 21(B)
(6) These are no forecasted plant additions for Category B

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Bethel-Norwalk
Sheet 1a

Line No.	(A)	Attachment I Reference Section:	(B)	(C) Source	(D) Notes
	I. INVESTMENT BASE				
1	Transmission Plant	II(A)(1)(a)	125,258,704	Sheet 2, Line 5	(a)
2	Transmission Plant Held for Future Use	II(A)(1)(b)	-	Sheet 2, Line 6	(a)
3	Accumulated Depreciation	II(A)(1)(c)	23,816,817	Sheet 2, Line 11	(a)
4	Accumulated Deferred Income Taxes	II(A)(1)(d)	19,494,337	Sheet 2, Line 12	(a)
5	Loss On Reacquired Debt	II(A)(1)(e)	187,920	Sheet 2, Line 13	(a)
6	Net Investment (Line 1+2-3-4+5)		82,135,470		(a)
7	Prepayments	II(A)(1)(f)	787,415	Sheet 2, Line 14	(a)
8	Materials & Supplies	II(A)(1)(g)	1,459,628	Sheet 2, Line 15	(a)
9	Cash Working Capital	II(A)(1)(h)	426,868	Sheet 2, Line 22	(b)
10	Total Investment Base (Line 6+7+8+9)		84,809,381		
	II. REVENUE REQUIREMENTS				
11	Investment Return and Income Taxes	II(A)	10,951,963	Sheet 4a, Line 15(4)	(b)
12	Depreciation Expense	II(B)	3,051,146	Sheet 8, Line 5	(a)
13	Amortization of Loss on Reacquired Debt	II(C)	19,538	Sheet 8, Line 6	(a)
14	Investment Tax Credit	II(D)	(22,551)	Sheet 8, Line 7	(a)
15	Property Tax Expense	II(E)	1,802,271	Sheet 8, Line 8	(a)
16	Payroll Tax Expense	II(F)	13,032	Sheet 8, Line 21	(a)
17	Operation & Maintenance Expense	II(G)	1,529,404	Sheet 8, Line 29	(a)
18	Administrative & General Expense	II(H)	2,221,121	Sheet 8, Line 40	(b)
19	Support Expenses	II(I)	-		(a)
20	Transmission Related Taxes and Fees	II(J)	398,198	Sheet 8, Line 41	(a)
21	Total Revenue Requirements (Line 11 thru 20)		19,964,122		(b)

Note:
Investment Return and Income Taxes (line 11 above) was calculated based on the Total Investment Base at 11.07% ROE, plus the Localized Post-2003 PTF Transmission Base (lines 1-3-4) at the .67% capped Incremental ROE.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Bethel-Norwalk
Sheet 2

Line No.	(A)	(B) Trans. Related Average		(C) Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Transmission Plant							
1	Localized Transmission Plant					121,745,648	Sheet 3, Line 19	(a)
2	Transmission General Plant	102,812,641	Note 4				FF1 page 204 ln. 96, footnote	(a)
3	Less: Convex-related General Plant	15,870,872					Note 1	(a)
4	Subtotal: General Plant, net of Convex (line 2 - 3)	86,941,769		4.0407%	Note 2	3,513,056		(a)
5	Total (line 1+4)					125,258,704		(a)
6	Localized Transmission Plant Held for Future Use					-		(a)
	Transmission Accumulated Depreciation							
7	Localized Transmission Accum. Depreciation					22,912,990	Sheet 9, Line 56(I)	(a)
8	General Plant Accum. Depreciation	26,085,325	Note 4				FF1 page 219 ln. 28, footnote	(a)
9	Less: Convex-related General Plant Acc Depr	3,717,252					Note 1	(a)
10	Subtotal: General Plant A/D, net of Convex (line 8-9)	22,368,074		4.0407%	Note 2	903,827		(a)
11	Total (line 7+10)					23,816,817		(a)
12	Transmission Accumulated Deferred Taxes					19,494,337	Sheet 10, Line 111	(a)
13	Unam. Loss on Reacquired Debt (189)	12,599,425		1.4915%	Note 3	187,920	FF1 page 111 ln. 81	(a)
14	Transmission Prepayments (165)	19,487,085	Note 4	4.0407%	Note 2	787,415	FF1 page 110 ln. 57, footnote	(a)
15	Transmission Materials and Supplies	36,123,136		4.0407%	Note 2	1,459,628	FF1 page 227 ln. 8	(a)
	Cash Working Capital							
16	Localized Operation & Maintenance Expense					1,529,404	Sheet 8, Line 29	(a)
17	Localized Administrative & General Expense					2,221,121	Sheet 8, Line 40	(b)
18	Subtotal (line 16+17)					3,750,525		(b)
19	12.5% allowance					0.125	x 45 / 360	(a)
20	Total current Year End (line 18*19)					468,816		(b)
21	Prior Year End Cash Working Capital					384,919	Note 1	(a)
22	Average Cash Working Capital [(line 20+21)/2]					426,868		(b)

Note 1: Reflects actual information per Eversource's accounting records.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Bethel-Norwalk
Sheet 4a

Line No.		(1) 2014 AVERAGE CAPITALIZATION	(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL	(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559 Note 2	46.27%	5.36% Note 2	2.48%		
2	PREFERRED STOCK	$ 116,842,775	2.14%	4.80%	0.10%	0.10%	
3	COMMON EQUITY	$ 2,820,159,065	51.59%	11.07% Note 1	5.71%	5.71%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399	100.00%		8.29%	5.81%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 8.29% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate) Total Inv. Base)) * Federal Income Tax Rate)

Source: Line 4, Col. (5); Sheet 8, Line 7; Sheet 6, Line 1; Sheet 1, Line 10; Federal Corporate Tax Rate

6 = ((5.81% + (((22,551) + 93,235) / 84,809,381)) * 35.00%)
7 (1 - 35.00% Federal Corporate Tax Rate)

8 = 3.1733%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate) Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)

Source: Line 4, Col. (5); Sheet 8, Line 7; Sheet 6, Line 1; Sheet 1, Line 10; Line 8, Col. (1); Connecticut Corporate Tax Rate

9 = ((5.81% + (((22,551) + 93,235) / 84,809,381) + 3.1733%) * 9.00%)
10 (1 - 9.00% Connecticut Corporate Tax Rate)

11 = 0.8967%

12 (a)+(b)+(c) **Cost of Capital Rate** = 12.3600%

13	INVESTMENT BASE	84,809,381	Sheet 1, Line 10
14			
15	x Cost of Capital Rate	12.3600%	Line 12, Col. (1)
16	= Investment Return and Income Taxes	$ 10,482,439	

Total Investment Return and Income Taxes		
@11.07%	$ 10,482,439	Line 16, Col. (1)
@.67%	$ 469,524	Sheet 5a, Line 17
	$ 10,951,963	To Sheet 1a, Line 11

Note 1: ROE per FERC Order in Docket No. ER11-66 dated October 16, 2014.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes:

(1) **Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247**
(2) **The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses**

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Bethel-Norwalk

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559	Note 2	46.27%					
2	PREFERRED STOCK	$ 116,842,775		2.14%					
3	COMMON EQUITY	$ 2,820,159,065		51.59%	0.50%	Note 1	0.26%	0.26%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399		100.00%			0.26%	0.26%	

Cost of Capital Rate=

Line													
5	(a) Weighted Cost of Capital	=	0.26% Line 4, Col. (4)										
	(b) Federal Income Tax	= ((	R.O.E.	+ ((	Total Inv. (Tax Credit)	+	Eq. AFUDC of Deprec. Exp.	) /	Total Inv. Base	)) *	Federal Income Tax Rate	)	
				(	1	-	Federal Income Tax Rate	)					
		Source:	Line 4, Col. (5)						Line 16, Col. (4)		Federal Corporate Tax Rate		
6		= ((	0.26%	+ ((	0	+	0	) /	84,809,381	)) *	35.00%	)	
7				(	1	-	35.00%	)					
							Federal Corporate Tax Rate						
8		=	0.1400%										
	(c) State Income Tax	= ((	R.O.E.	+ ((	Total Inv. (Tax Credit)	+	Eq. AFUDC of Deprec. Exp.	) /	Total Inv. Base	) +	Federal Income Tax	) *	State Income Tax Rate)
				(	1	-	State Income Tax Rate	)					
		Source:	Line 4, Col. (5)						Line 16, Col. (4)		Line 8, Col. (1)		Connecticut Corporate Tax Rate
9		= ((	0.26%	+ ((	0	+	0	) /	84,809,381	) +	0.1400%	) *	9.00%)
10				(	1	-	9.00%	)					
							Connecticut Corporate Tax Rate						
11		=	0.0396%										
12	(a)+(b)+(c) **Cost of Capital Rate**	=	0.4396%										
13	INVESTMENT BASE		84,809,381 Line 16, Col. (4)										
14	x Cost of Capital Rate		0.4396% Line 12, Col. (1)										
15	= Investment Return and Income Taxes	$	372,822 to Sheet 4a, Line 14(4)										

Note 1: CAP on ROE incentives per FERC Order in Docket No. EL11-66 dated March 3, 2015.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.

Notes:

(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-217, Schedule 1, Page 2 of 2, Line 18
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Bethel-Norwalk
Sheet 8

Line No.	(A)	(B) Year End		(C) Localized Trans. Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Depreciation Expense							
1	Transmission Depreciation					2,894,776	Sheet 9, Line 58	(a)
2	General Depreciation	4,980,574	Note 4				FF1 page 336 ln. 10, footnote	(a)
3	*less:* Convex-related General Plant Depreciation Expense	1,110,693					Note 1	(a)
4	Subtotal: General Plant Depr Exp, net of Convex (line 2-3)	3,869,881		4.0407%	Note 2	156,370		(a)
5	Total (line 1+4)					3,051,146		(a)
6	Amortization of Loss on Reacquired Debt	1,309,927		1.4915%	Note 3	19,538	FF1 page 117 ln. 64	(a)
7	Amortization of Investment Tax Credits	1,511,975		1.4915%	Note 3	22,551	FF1 page 266 ln. 8 (f)	(a)
8	Property Taxes	120,836,131		1.4915%	Note 3	1,802,271	FF1 page 263 ln. 24i & 25i	(a)
	Payroll Tax Expense							
9	Federal Unemployment	5,226					FF1 page 262 ln. 3i, footnote	(a)
10	FICA	233,351					FF1 page 262 ln. 5i, footnote	(a)
11	Medicare	65,613					FF1 page 262 ln. 9i, footnote	(a)
12	CT Unemployment	16,786					FF1 page 262 ln. 15i, footnote	(a)
13	MA Unemployment	(285)					FF1 page 262 ln. 32i, footnote	(a)
14	MA Universal Health	64					FF1 page 262 ln. 33i, footnote	(a)
15	NH Unemployment	1,754					FF1 page 262.1 ln. 4i, footnote	(a)
16	NJ Unemployment	-					FF1 page 262 footnote	(a)
17	DC Unemployment	11					FF1 page 262.1 ln. 14i, footnote	(a)
18	FL Unemployment	1					FF1 page 262.1 ln. 18i, footnote	(a)
19	MI Unemployment	6					FF1 page 262.1 ln. 22i, footnote	(a)
20	NY Unemployment	-					FF1 page 262.1 ln. 10i, footnote	(a)
21	Total (Line 9 to 20)	322,527	Note 4	4.0407%	Note 2	13,032		
	Transmission Operation and Maintenance							
22	Operation and Maintenance	77,432,007					FF1 page 321 ln. 112	(a)
23	Transmission of Electricity by Others - #565	21,727,966					FF1 page 321 ln. 96	(a)
24	Load Dispatching - #561	-					FF1 page 321 ln. 84	(a)
25	Account 561.1	3,245,594					FF1 page 321 ln. 85	(a)
26	Account 561.2	5,212,556					FF1 page 321 ln. 86	(a)
27	Account 561.3	2,238,612					FF1 page 321 ln. 87	(a)
28	Account 561.4	7,157,291					FF1 page 321 ln. 88	(a)
29	O&M (line 22 - lines 23 to 28)	37,849,988		4.0407%	Note 2	1,529,404		(a)
	Transmission-related Administrative and General							
30	Administrative and General	37,202,294	Note 4				FF1 page 320 ln. 197 b, footnote	(a)
31	less: Property Insurance (#924)	763,857	Note 4				FF1 Page 320 ln. 185 b, footnote	(a)
32	less: Regulatory Commission Expenses (#928)	2,749,411	Note 4				FF1 page 320 ln. 189 b, footnote	(a)
33	less: General Advertising Expense (#930.1)	10,766	Note 4				FF1 page 320 ln. 191 b, footnote	(a)
34	Subtotal (line 30 - lines 31 to 33)	33,678,260		4.0407%	Note 2	1,360,837		(a)
35	plus: Property Insurance	1,413,419		1.4915%	Note 3	21,081	FF1 page 323 ln. 185	(a)
36	plus: Trans. Regulatory Comm. Exp.	2,749,411		4.0407%	Note 2	111,095	FF1 page 320 ln. 189 b, footnote	(a)
37	plus: Trans. Related General Advertising Expense	10,766		4.0407%	Note 2	435	FF1 page 320 ln. 191 b, footnote	(a)
38	plus: Trans. Related Public Education Expense	-				-	FF1 page 114 ln. 49, footnote	(a)
39	plus: Trans. Merger-Related Costs	18,008,593		4.0407%		727,673	Exhibit No. ES-201, Page 1 of 1, Line 23(H)	(b)
40	Total A&G (sum of lines 34 to 38)	55,860,449				2,221,121		(b)
41	Transmission Related Taxes and Fees	9,854,673		4.0407%	Note 2	398,198	Note 5	(a)

Note 1: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.
Note 5: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment B.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Middletown-Norwalk
Sheet 1a

Line No.	(A)	Attachment I Reference Section:	(B)	(C) Source	(D) Notes
	I. INVESTMENT BASE				
1	Transmission Plant	II(A)(1)(a)	62,028,638	Sheet 2, Line 5	(a)
2	Transmission Plant Held for Future Use	II(A)(1)(b)	-	Sheet 2, Line 6	(a)
3	Accumulated Depreciation	II(A)(1)(c)	9,382,562	Sheet 2, Line 11	(a)
4	Accumulated Deferred Income Taxes	II(A)(1)(d)	7,626,580	Sheet 2, Line 12	(a)
5	Loss On Reacquired Debt	II(A)(1)(e)	93,059	Sheet 2, Line 13	(a)
6	Net Investment (Line 1+2-3-4+5)		45,112,555		(a)
7	Prepayments	II(A)(1)(f)	389,937	Sheet 2, Line 14	(a)
8	Materials & Supplies	II(A)(1)(g)	722,824	Sheet 2, Line 15	(a)
9	Cash Working Capital	II(A)(1)(h)	211,478	Sheet 2, Line 22	(b)
10	Total Investment Base (Line 6+7+8+9)		46,436,794		
II.	REVENUE REQUIREMENTS				
11	Investment Return and Income Taxes	II(A)	5,995,859	Sheet 4a, Line 15(4)	(b)
12	Depreciation Expense	II(B)	1,584,643	Sheet 8, Line 5	(a)
13	Amortization of Loss on Reacquired Debt	II(C)	9,675	Sheet 8, Line 6	(a)
14	Investment Tax Credit	II(D)	(11,167)	Sheet 8, Line 7	(a)
15	Property Tax Expense	II(E)	892,496	Sheet 8, Line 8	(a)
16	Payroll Tax Expense	II(F)	6,454	Sheet 8, Line 21	(a)
17	Operation & Maintenance Expense	II(G)	757,378	Sheet 8, Line 29	(a)
18	Administrative & General Expense	II(H)	1,099,925	Sheet 8, Line 40	(b)
19	Support Expenses	II(I)	-		(a)
20	Transmission Related Taxes and Fees	II(J)	197,192	Sheet 8, Line 41	(a)
21	Total Revenue Requirements (Line 11 thru 20)		10,532,455		(b)

Note:
Investment Return and Income Taxes (line 11 above) was calculated based on the Total Investment Base at 11.07% ROE, plus the Localized Post-2003 PTF Transmission Base (lines 1-3-4) at the .67% capped Incremental ROE.

Notes:

(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247

(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Middletown-Norwalk
Sheet 2

Line No.	(A)	(B) Trans. Related Average		(C) Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Transmission Plant							
1	Localized Transmission Plant					60,288,933	Sheet 3, Line 18	(a)
2	Transmission General Plant	102,812,641	Note 4				FF1 page 204 ln. 96, footnote	(a)
3	Less: Convex-related General Plant	15,870,872					Note 1	(a)
4	Subtotal: General Plant, net of Convex (line 2 - 3)	86,941,769		2.0010%	Note 2	1,739,705		(a)
5	Total (line 1+4)					62,028,638		(a)
6	Localized Transmission Plant Held for Future Use					-		(a)
	Transmission Accumulated Depreciation							
7	Localized Transmission Accum. Depreciation					8,934,977	Sheet 9, Line 84(I)	(a)
8	General Plant Accum. Depreciation	26,085,325	Note 4				FF1 page 219 ln. 28, footnote	(a)
9	Less: Convex-related General Plant Acc Depr	3,717,252					Note 1	(a)
10	Subtotal: General Plant A/D, net of Convex (line 8-9)	22,368,074		2.0010%	Note 2	447,585		(a)
11	Total (line 7+10)					9,382,562		(a)
12	Transmission Accumulated Deferred Taxes					7,626,580	Sheet 10, Line 105	(a)
13	Unam. Loss on Reacquired Debt (189)	12,599,425		0.7386%	Note 3	93,059	FF1 page 111 ln. 81	(a)
14	Transmission Prepayments (165)	19,487,085	Note 4	2.0010%	Note 2	389,937	FF1 page 110 ln. 57, footnote	(a)
15	Transmission Materials and Supplies	36,123,136		2.0010%	Note 2	722,824	FF1 page 227 ln. 8	(a)
	Cash Working Capital							
16	Localized Operation & Maintenance Expense					757,378	Sheet 8, Line 29	(a)
17	Localized Administrative & General Expense					1,099,925	Sheet 8, Line 40	(b)
18	Subtotal (line 16+17)					1,857,303		(b)
19	12.5% allowance					0.125	x 45 / 360	(a)
20	Total current Year End (line 18*19)					232,163		(b)
21	Prior Year End Cash Working Capital					190,793	Note 1	(a)
22	Average Cash Working Capital [(line 20+21)/2]					211,478		(b)

Note 1: Reflects actual information per the Company's accounting records.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Middletown-Norwalk
Sheet 4a

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559	Note 2	46.27%	5.36%	Note 2	2.48%		
2	PREFERRED STOCK	$ 116,842,775		2.14%	4.80%		0.10%	0.10%	
3	COMMON EQUITY	$ 2,820,159,065		51.59%	11.07%	Note 1	5.71%	5.71%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399		100.00%			8.29%	5.81%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 8.29% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) / (1 - Federal Income Tax Rate) + Eq. AFUDC of Deprec. Exp. / (1 - Federal Income Tax Rate)) / Total Inv. Base)) * Federal Income Tax Rate)

Source: Line 4, Col. (5); Sheet 8, Line 7; Sheet 6, Line 1; Sheet 1, Line 10; Federal Corporate Tax Rate

6 = ((5.81% + (((11,167) + 46,171) / (1 - 35.00%)) / 46,436,794)) * 35.00%)
7 Federal Corporate Tax Rate

8 = 3.1691%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate)) / Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)

Source: Line 4, Col. (5); Sheet 8, Line 7; Sheet 6, Line 1; Sheet 1, Line 10; Line 8, Col. (1); Connecticut Corporate Tax Rate

9 = ((5.81% + (((11,167) + 46,171) / (1 - 9.00%)) / 46,436,794) + 3.1691%) * 9.00%)
10 Connecticut Corporate Tax Rate

11 = 0.8955%

12 (a)+(b)+(c) **Cost of Capital Rate** = 12.3546%

13	INVESTMENT BASE	46,436,794	Sheet 1, Line 10
14			
15	x Cost of Capital Rate	12.3546%	Line 12, Col. (1)
16	= Investment Return and Income Taxes	$ 5,737,080	

Total Investment Return and Income Taxes		
@11.07%	$ 5,737,080	Line 16, Col. (1)
@.67%	$ 258,779	Sheet 5a, Line 17
	$ 5,995,859	To Sheet 1a, Line 11

Note 1: ROE per FERC Order in Docket No. ER11-66 dated October 16, 2014.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes:

(1) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Middletown-Norwalk
Sheet 5a

Line No.		(1) 2014 AVERAGE CAPITALIZATION	(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL	(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559 Note 2	46.27%				
2	PREFERRED STOCK	$ 116,842,775	2.14%				
3	COMMON EQUITY	$ 2,820,159,065	51.59%	0.50% Note 1	0.26%	0.26%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399	100.00%		0.26%	0.26%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.26% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate) Total Inv. Base)) * Federal Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Federal Corporate Tax Rate

6 = ((0.26% + ((0 + 0) / 46,436,794)) * 35.00%)
7 (1 - 35.00%) Federal Corporate Tax Rate

8 = 0.1400%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate) Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Line 8, Col. (1); Connecticut Corporate Tax Rate

9 = ((0.26% + ((0 + 0) / 46,436,794) + 0.1400%) * 9.00%)
10 (1 - 9.00%) Connecticut Corporate Tax Rate

11 = 0.0396%

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.4396%

13	INVESTMENT BASE	46,436,794	Line 16, Col. (4)
14	x Cost of Capital Rate	0.4396%	Line 12, Col. (1)
15	= Investment Return and Income Taxes	$ 204,136	to Sheet 4a, Line 14(4)

Note 1: CAP on ROE incentives per FERC Order in Docket No. EL11-66 dated March 3, 2015.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.

Notes:

(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-217, Schedule 1, Page 2 of 2, Line 18
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Middletown-Norwalk
Sheet 8

Line No.	(A)	(B) Year End		(C) Localized Trans. Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Depreciation Expense							
1	Transmission Depreciation					1,507,207	Sheet 9, Line 86	(a)
2	General Depreciation	4,980,574	Note 4				FF1 page 336 ln. 10, footnote	(a)
3	*less:* Convex-related General Plant Depreciation Expense	1,110,693					Note 1	(a)
4	Subtotal: General Plant Depr Exp, net of Convex (line 2-3)	3,869,881		2.0010%	Note 2	77,436		(a)
5	Total (line 1+4)					1,584,643		(a)
6	Amortization of Loss on Reacquired Debt	1,309,927		0.7386%	Note 3	9,675	FF1 page 117 ln. 64	(a)
7	Amortization of Investment Tax Credits	1,511,975		0.7386%	Note 3	11,167	FF1 page 266 ln. 8 (f)	(a)
8	Property Taxes	120,836,131		0.7386%	Note 3	892,496	FF1 page 263 ln. 24i & 25i	(a)
	Payroll Tax Expense							
9	Federal Unemployment	5,226					FF1 page 262 ln. 3i, footnote	(a)
10	FICA	233,351					FF1 page 262 ln. 5i, footnote	(a)
11	Medicare	65,613					FF1 page 262 ln. 9i, footnote	(a)
12	CT Unemployment	16,786					FF1 page 262 ln. 15i, footnote	(a)
13	MA Unemployment	(285)					FF1 page 262 ln. 32i, footnote	(a)
14	MA Universal Health	64					FF1 page 262 ln. 33i, footnote	(a)
15	NH Unemployment	1,754					FF1 page 262.1 ln. 4i, footnote	(a)
16	NJ Unemployment	-					FF1 page 262 footnote	(a)
17	DC Unemployment	11					FF1 page 262.1 ln. 14i, footnote	(a)
18	FL Unemployment	1					FF1 page 262.1 ln. 18i, footnote	(a)
19	MI Unemployment	6					FF1 page 262.1 ln. 22i, footnote	(a)
20	NY Unemployment	-					FF1 page 262.1 ln. 10i, footnote	(a)
21	Total (Line 9 to 20)	322,527	Note 4	2.0010%	Note 2	6,454		
	Transmission Operation and Maintenance							
22	Operation and Maintenance	77,432,007					FF1 page 321 ln. 112	(a)
23	Transmission of Electricity by Others - #565	21,727,966					FF1 page 321 ln. 96	(a)
24	Load Dispatching - #561	-					FF1 page 321 ln. 84	(a)
25	Account 561.1	3,245,594					FF1 page 321 ln. 85	(a)
26	Account 561.2	5,212,556					FF1 page 321 ln. 86	(a)
27	Account 561.3	2,238,612					FF1 page 321 ln. 87	(a)
28	Account 561.4	7,157,291					FF1 page 321 ln. 88	(a)
29	O&M (line 22 - lines 23 to 28)	37,849,988		2.0010%	Note 2	757,378		(a)
	Transmission-related Administrative and General							
30	Administrative and General	37,202,294	Note 4				FF1 page 320 ln. 197 b, footnote	(a)
31	less: Property Insurance (#924)	763,857	Note 4				FF1 Page 320 ln. 185 b, footnote	(a)
32	less: Regulatory Commission Expenses (#928)	2,749,411	Note 4				FF1 page 320 ln. 189 b, footnote	(a)
33	less: General Advertising Expense (#930.1)	10,766	Note 4				FF1 page 320 ln. 191 b, footnote	(a)
34	Subtotal (line 30 - lines 31 to 33)	33,678,260		2.0010%	Note 2	673,902		(a)
35	plus: Property Insurance	1,413,419		0.7386%	Note 3	10,440	FF1 page 323 ln. 185	(a)
36	plus: Trans. Regulatory Comm. Exp.	2,749,411		2.0010%	Note 2	55,016	FF1 page 320 ln. 189 b, footnote	(a)
37	plus: Trans. Related General Advertising Expense	10,766		2.0010%	Note 2	215	FF1 page 320 ln. 191 b, footnote	(a)
38	plus: Trans. Related Public Education Expense	-				-	FF1 page 114 ln. 49, footnote	(a)
39	plus: Trans. Merger-Related Costs	18,008,593		2.0010%		360,352	Exhibit No. ES-201, Page 1 of 1, Line 23(H)	(b)
40	Total A&G (sum of lines 34 to 38)	55,860,449				1,099,925		(b)
41	Transmission Related Taxes and Fees	9,854,673		2.0010%	Note 2	197,192	Note 5	(a)

Note 1: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.
Note 5: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment B.

Notes:

(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Glenbrook Cables
Sheet 1a

Line No.	(A)	Attachment I Reference Section:	(B)	(C) Source	(D) Notes
	I. INVESTMENT BASE				
1	Transmission Plant	II(A)(1)(a)	2,644,161	Sheet 2, Line 5	(a)
2	Transmission Plant Held for Future Use	II(A)(1)(b)	31,396,972	Sheet 2, Line 6	(a)
3	Accumulated Depreciation	II(A)(1)(c)	353,497	Sheet 2, Line 11	(a)
4	Accumulated Deferred Income Taxes	II(A)(1)(d)	323,209	Sheet 2, Line 12	(a)
5	Loss On Reacquired Debt	II(A)(1)(e)	3,969	Sheet 2, Line 13	(a)
6	Net Investment (Line 1+2-3-4+5)		33,368,396		(a)
7	Prepayments	II(A)(1)(f)	16,622	Sheet 2, Line 14	(a)
8	Materials & Supplies	II(A)(1)(g)	30,813	Sheet 2, Line 15	(a)
9	Cash Working Capital	II(A)(1)(h)	9,016	Sheet 2, Line 22	(b)
10	Total Investment Base (Line 6+7+8+9)		33,424,847		
	II. REVENUE REQUIREMENTS				
11	Investment Return and Income Taxes	II(A)	4,124,445	Sheet 4a, Line 15(4)	(b)
12	Depreciation Expense	II(B)	63,152	Sheet 8, Line 5	(a)
13	Amortization of Loss on Reacquired Debt	II(C)	413	Sheet 8, Line 6	(a)
14	Investment Tax Credit	II(D)	(476)	Sheet 8, Line 7	(a)
15	Property Tax Expense	II(E)	38,063	Sheet 8, Line 8	(a)
16	Payroll Tax Expense	II(F)	275	Sheet 8, Line 21	(a)
17	Operation & Maintenance Expense	II(G)	32,286	Sheet 8, Line 29	(a)
18	Administrative & General Expense	II(H)	46,888	Sheet 8, Line 40	(b)
19	Support Expenses	II(I)	-		(a)
20	Transmission Related Taxes and Fees	II(J)	8,406	Sheet 8, Line 41	(a)
21	Total Revenue Requirements (Line 11 thru 20)		4,313,452		(b)

Note:
Investment Return and Income Taxes (line 11 above) was calculated based on the Total Investment Base at 11.07% ROE, plus the Localized Post-2003 PTF Transmission Base (lines 1-3-4) at the .67% capped Incremental ROE.

Notes:

(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247

(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Glenbrook Cables
Sheet 2

Line No.	(A)	(B) Trans. Related Average		(C) Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Transmission Plant							
1	Localized Transmission Plant					2,570,000	Sheet 3, Line 17	(a)
2	Transmission General Plant	102,812,641	Note 4				FF1 page 204 ln. 96, footnote	(a)
3	Less: Convex-related General Plant	15,870,872					Note 1	(a)
4	Subtotal: General Plant, net of Convex (line 2 - 3)	86,941,769		0.0853%	Note 2	74,161		(a)
5	Total (line 1+4)					2,644,161		(a)
6	Localized Transmission Plant Held for Future Use					31,396,972		(a)
	Transmission Accumulated Depreciation							
7	Localized Transmission Accum. Depreciation					334,418	Sheet 9, Line 17(I)	(a)
8	General Plant Accum. Depreciation	26,085,325	Note 4				FF1 page 219 ln. 28, footnote	(a)
9	Less: Convex-related General Plant Acc Depr	3,717,252					Note 1	(a)
10	Subtotal: General Plant A/D, net of Convex (line 8-9)	22,368,074		0.0853%	Note 2	19,080		(a)
11	Total (line 7+10)					353,497		(a)
12	Transmission Accumulated Deferred Taxes					323,209	Sheet 10, Line 32	(a)
13	Unam. Loss on Reacquired Debt (189)	12,599,425		0.0315%	Note 3	3,969	FF1 page 111 ln. 81	(a)
14	Transmission Prepayments (165)	19,487,085	Note 4	0.0853%	Note 2	16,622	FF1 page 110 ln. 57, footnote	(a)
15	Transmission Materials and Supplies	36,123,136		0.0853%	Note 2	30,813	FF1 page 227 ln. 8	(a)
	Cash Working Capital							
16	Localized Operation & Maintenance Expense					32,286	Sheet 8, Line 29	(a)
17	Localized Administrative & General Expense					46,888	Sheet 8, Line 40	(b)
18	Subtotal (line 16+17)					79,174		(b)
19	12.5% allowance					0.125	x 45 / 360	(a)
20	Total current Year End (line 18*19)					9,897		(b)
21	Prior Year End Cash Working Capital					8,135	Note 1	(a)
22	Average Cash Working Capital [(line 20+21)/2]					9,016		(b)

Note 1: Reflects actual information per Eversource's accounting records.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Glenbrook Cables
Sheet 4a

Line No.		(1) 2014 AVERAGE CAPITALIZATION	(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL	(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559 Note 2	46.27%	5.36% Note 2	2.48%		
2	PREFERRED STOCK	$ 116,842,775	2.14%	4.80%	0.10%	0.10%	
3	COMMON EQUITY	$ 2,820,159,065	51.59%	11.07% Note 1	5.71%	5.71%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399	100.00%		8.29%	5.81%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 8.29% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate) Total Inv. Base)) * Federal Income Tax Rate)

Source: Line 4, Col. (5); Sheet 8, Line 7; Sheet 6, Line 1; Sheet 1, Line 10; Federal Corporate Tax Rate

6 = ((5.81% + (((476) + 1,968) /
7 (1 - 35.00%) 33,424,847)) * 35.00%)

Federal Corporate Tax Rate

8 = 3.1309%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate) Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)

Source: Line 4, Col. (5); Sheet 8, Line 7; Sheet 6, Line 1; Sheet 1, Line 10; Line 8, Col. (1); Connecticut Corporate Tax Rate

9 = ((5.81% + (((476) + 1,968) /
10 (1 - 9.00%) 33,424,847) + 3.1309%) * 9.00%)

Connecticut Corporate Tax Rate

11 = 0.8847%

12 (a)+(b)+(c) **Cost of Capital Rate** = 12.3056%

13	INVESTMENT BASE	33,424,847	Sheet 1, Line 10
14			
15	x Cost of Capital Rate	12.3056%	Line 12, Col. (1)
16	= Investment Return and Income Taxes	$ 4,113,128	

Total Investment Return and Income Taxes		
@11.07%	$ 4,113,128	Line 16, Col. (1)
@.67%	$ 11,317	Sheet 5a, Line 17
	$ 4,124,445	To Sheet 1a, Line 11

Note 1: ROE per FERC Order in Docket No. ER11-66 dated October 16, 2014.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes:

(1) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Glenbrook Cables

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL	(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559	Note 2	46.27%				
2	PREFERRED STOCK	$ 116,842,775		2.14%				
3	COMMON EQUITY	$ 2,820,159,065		51.59%	0.50% Note 1	0.26%	0.26%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399		100.00%		0.26%	0.26%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.26% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / Total Inv. Base)) * Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Federal Corporate Tax Rate

6 = ((0.26% + ((0 + 0) / 33,424,847)) * 35.00%)
7 (1 - 35.00%) Federal Corporate Tax Rate

8 = 0.1400%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / Total Inv. Base) + Federal Income Tax) * State Income Tax Rate) / (1 - State Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Line 8, Col. (1); Connecticut Corporate Tax Rate

9 = ((0.26% + ((0 + 0) / 33,424,847) + 0.1400%) * 9.00%)
10 (1 - 9.00%) Connecticut Corporate Tax Rate

11 = 0.0396%

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.4396%

13	INVESTMENT BASE	33,424,847	Line 16, Col. (4)
14	x Cost of Capital Rate	0.4396%	Line 12, Col. (1)
15	= Investment Return and Income Taxes	$ 146,936	to Sheet 4a, Line 14(4)

Note 1: CAP on ROE incentives per FERC Order in Docket No. EL11-66 dated March 3, 2015.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.

Notes:

(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-217, Schedule 1, Page 2 of 2, Line 18
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Glenbrook Cables
Sheet 8

Line No.	(A)	(B) Year End		(C) Localized Trans. Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Depreciation Expense							
1	Transmission Depreciation					59,851	Sheet 9, Line 19	(a)
2	General Depreciation	4,980,574	Note 4				FF1 page 336 ln. 10, footnote	(a)
3	*less:* Convex-related General Plant Depreciation Expense	1,110,693					Note 1	(a)
4	Subtotal: General Plant Depr Exp, net of Convex (line 2-3)	3,869,881		0.0853%	Note 2	3,301		(a)
5	Total (line 1+4)					63,152		(a)
6	Amortization of Loss on Reacquired Debt	1,309,927		0.0315%	Note 3	413	FF1 page 117 ln. 64	(a)
7	Amortization of Investment Tax Credits	1,511,975		0.0315%	Note 3	476	FF1 page 266 ln. 8 (f)	(a)
8	Property Taxes	120,836,131		0.0315%	Note 3	38,063	FF1 page 263 ln. 24i & 25i	(a)
	Payroll Tax Expense							
9	Federal Unemployment	5,226					FF1 page 262 ln. 3i, footnote	(a)
10	FICA	233,351					FF1 page 262 ln. 5i, footnote	(a)
11	Medicare	65,613					FF1 page 262 ln. 9i, footnote	(a)
12	CT Unemployment	16,786					FF1 page 262 ln. 15i, footnote	(a)
13	MA Unemployment	(285)					FF1 page 262 ln. 32i, footnote	(a)
14	MA Universal Health	64					FF1 page 262 ln. 33i, footnote	(a)
15	NH Unemployment	1,754					FF1 page 262.1 ln. 4i, footnote	(a)
16	NJ Unemployment	-					FF1 page 262 footnote	(a)
17	DC Unemployment	11					FF1 page 262.1 ln. 14i, footnote	(a)
18	FL Unemployment	1					FF1 page 262.1 ln. 18i, footnote	(a)
19	MI Unemployment	6					FF1 page 262.1 ln. 22i, footnote	(a)
20	NY Unemployment	-					FF1 page 262.1 ln. 10i, footnote	(a)
21	Total (Line 9 to 20)	322,527	Note 4	0.0853%	Note 2	275		
	Transmission Operation and Maintenance							
22	Operation and Maintenance	77,432,007					FF1 page 321 ln. 112	(a)
23	Transmission of Electricity by Others - #565	21,727,966					FF1 page 321 ln. 96	(a)
24	Load Dispatching - #561	-					FF1 page 321 ln. 84	(a)
25	Account 561.1	3,245,594					FF1 page 321 ln. 85	(a)
26	Account 561.2	5,212,556					FF1 page 321 ln. 86	(a)
27	Account 561.3	2,238,612					FF1 page 321 ln. 87	(a)
28	Account 561.4	7,157,291					FF1 page 321 ln. 88	(a)
29	O&M (line 22 - lines 23 to 28)	37,849,988		0.0853%	Note 2	32,286		(a)
	Transmission-related Administrative and General							
30	Administrative and General	37,202,294	Note 4				FF1 page 320 ln. 197 b, footnote	(a)
31	**less:** Property Insurance (#924)	763,857	Note 4				FF1 Page 320 ln. 185 b, footnote	(a)
32	**less:** Regulatory Commission Expenses (#928)	2,749,411	Note 4				FF1 page 320 ln. 189 b, footnote	(a)
33	**less:** General Advertising Expense (#930.1)	10,766	Note 4				FF1 page 320 ln. 191 b, footnote	(a)
34	Subtotal (line 30 - lines 31 to 33)	33,678,260		0.0853%	Note 2	28,728		(a)
35	**plus:** Property Insurance	1,413,419		0.0315%	Note 3	445	FF1 page 323 ln. 185	(a)
36	**plus:** Trans. Regulatory Comm. Exp.	2,749,411		0.0853%	Note 2	2,345	FF1 page 320 ln. 189 b, footnote	(a)
37	**plus:** Trans. Related General Advertising Expense	10,766		0.0853%	Note 2	9	FF1 page 320 ln. 191 b, footnote	(a)
38	**plus:** Trans. Related Public Education Expense	-				-	FF1 page 114 ln. 49, footnote	(a)
39	**plus:** Trans. Merger-Related Costs	18,008,593		0.0853%		15,361	Exhibit No. ES-201, Page 1 of 1, Line 23(H)	(b)
40	Total A&G (sum of lines 34 to 38)	55,860,449				46,888		(b)
41	Transmission Related Taxes and Fees	9,854,673		0.0853%	Note 2	8,406	Note 5	(a)

Note 1: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.
Note 5: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment B.

Notes:

(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 1a

Line No.	(A)	Attachment I Reference Section:	(B)	(C) Source	(D) Notes
	I. INVESTMENT BASE				
1	Transmission Plant	II(A)(1)(a)	3,169,795	Sheet 2, Line 5	(a)
2	Transmission Plant Held for Future Use	II(A)(1)(b)	-	Sheet 2, Line 6	(a)
3	Accumulated Depreciation	II(A)(1)(c)	116,694	Sheet 2, Line 11	(a)
4	Accumulated Deferred Income Taxes	II(A)(1)(d)	265,445	Sheet 2, Line 12	(a)
5	Loss On Reacquired Debt	II(A)(1)(e)	4,750	Sheet 2, Line 13	(a)
6	Net Investment (Line 1+2-3-4+5)		2,792,406		(a)
7	Prepayments	II(A)(1)(f)	19,935	Sheet 2, Line 14	(a)
8	Materials & Supplies	II(A)(1)(g)	36,954	Sheet 2, Line 15	(a)
9	Cash Working Capital	II(A)(1)(h)	5,935	Sheet 2, Line 22	(b)
10	Total Investment Base (Line 6+7+8+9)		2,855,230		
	II. REVENUE REQUIREMENTS				
11	Investment Return and Income Taxes	II(A)	368,607	Sheet 4a, Line 15(4)	(b)
12	Depreciation Expense	II(B)	78,802	Sheet 8, Line 5	(a)
13	Amortization of Loss on Reacquired Debt	II(C)	494	Sheet 8, Line 6	(a)
14	Investment Tax Credit	II(D)	(570)	Sheet 8, Line 7	(a)
15	Property Tax Expense	II(E)	45,555	Sheet 8, Line 8	(a)
16	Payroll Tax Expense	II(F)	330	Sheet 8, Line 21	(a)
17	Operation & Maintenance Expense	II(G)	38,721	Sheet 8, Line 29	(a)
18	Administrative & General Expense	II(H)	56,233	Sheet 8, Line 40	(b)
19	Support Expenses	II(I)	-		(a)
20	Transmission Related Taxes and Fees	II(J)	10,081	Sheet 8, Line 41	(a)
21	Total Revenue Requirements (Line 11 thru 20)		598,253		(b)

Note:
Investment Return and Income Taxes (line 11 above) was calculated based on the Total Investment Base at 11.07% ROE, plus the Localized PTF Transmission Base (lines 1-3-4) at the .67% capped Incremental ROE.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 2

Line No.	(A)	(B) Trans. Related Average		(C) Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Transmission Plant							
1	Localized Transmission Plant					3,080,854	Sheet 3, Line 18	(a)
2	Transmission General Plant	102,812,641	Note 4				FF1 page 204 ln. 96, footnote	(a)
3	Less: Convex-related General Plant	15,870,872					Note 1	(a)
4	Subtotal: General Plant, net of Convex (line 2 - 3)	86,941,769		0.1023%	Note 2	88,941		(a)
5	Total (line 1+4)					3,169,795		(a)
6	Localized Transmission Plant Held for Future Use					-		(a)
	Transmission Accumulated Depreciation							
7	Localized Transmission Accum. Depreciation					93,811	Sheet 9, Line 10(I)	(a)
8	General Plant Accum. Depreciation	26,085,325	Note 4				FF1 page 219 ln. 28, footnote	(a)
9	Less: Convex-related General Plant Acc Depr	3,717,252					Note 1	(a)
10	Subtotal: General Plant A/D, net of Convex (line 8-9)	22,368,074		0.1023%	Note 2	22,883		(a)
11	Total (line 7+10)					116,694		(a)
12	Transmission Accumulated Deferred Taxes					265,445	Sheet 10, Line 46	(a)
13	Unam. Loss on Reacquired Debt (189)	12,599,425		0.0377%	Note 3	4,750	FF1 page 111 ln. 81	(a)
14	Transmission Prepayments (165)	19,487,085	Note 4	0.1023%	Note 2	19,935	FF1 page 110 ln. 57, footnote	(a)
15	Transmission Materials and Supplies	36,123,136		0.1023%	Note 2	36,954	FF1 page 227 ln. 8	(a)
	Cash Working Capital							
16	Localized Operation & Maintenance Expense					38,721	Sheet 8, Line 29	(a)
17	Localized Administrative & General Expense					56,233	Sheet 8, Line 40	(b)
18	Subtotal (line 16+17)					94,954		(b)
19	12.5% allowance					0.125	x 45 / 360	(a)
20	Total current Year End (line 18*19)					11,869		(b)
21	Prior Year End Cash Working Capital					-	Note 1	(a)
22	Average Cash Working Capital [(line 20+21)/2]					5,935		(b)

Note 1: Reflects actual information per Eversource's accounting records.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 4a

Line No.		(1) 2014 AVERAGE CAPITALIZATION	(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL	(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559 Note 2	46.27%	5.36% Note 2	2.48%		
2	PREFERRED STOCK	$ 116,842,775	2.14%	4.80%	0.10%	0.10%	
3	COMMON EQUITY	$ 2,820,159,065	51.59%	11.07% Note 1	5.71%	5.71%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399	100.00%		8.29%	5.81%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 8.29% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate) Total Inv. Base)) * Federal Income Tax Rate)

Line		R.O.E.		Total Inv. (Tax Credit)		Eq. AFUDC of Deprec. Exp.		Total Inv. Base		Federal Income Tax Rate	
	Source:	Line 4, Col. (5)		Sheet 8, Line 7		Sheet 6, Line 1		Sheet 1, Line 10		Federal Corporate Tax Rate	
6	= ((	5.81%	+ ((	(570)	+	2,360	) /	2,855,230	)) *	35.00%	)
7			(	1	-	35.00% Federal Corporate Tax Rate	)				
8	=	3.1622%									

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate) Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)

Line		R.O.E.		Total Inv. (Tax Credit)		Eq. AFUDC of Deprec. Exp.		Total Inv. Base		Federal Income Tax		State Income Tax Rate	
	Source:	Line 4, Col. (5)		Sheet 8, Line 7		Sheet 6, Line 1		Sheet 1, Line 10		Line 8, Col. (1)		Connecticut Corporate Tax Rate	
9	= ((	5.81%	+ ((	(570)	+	2,360	) /	2,855,230	) +	3.1622%	) *	9.00%	)
10			(	1	-	9.00% Connecticut Corporate Tax Rate	)						
11	=	0.8936%											

12 (a)+(b)+(c) **Cost of Capital Rate** = 12.3458%

Line			
13	INVESTMENT BASE	2,855,230	Sheet 1, Line 10
14			
15	x Cost of Capital Rate	12.3458%	Line 12, Col. (1)
16	= Investment Return and Income Taxes	$ 352,501	

Total Investment Return and Income Taxes			
@11.07%	$	352,501	Line 16, Col. (1)
@.67%	$	16,106	Sheet 5a, Line 17
	$	368,607	To Sheet 1a, Line 11

Note 1: ROE per FERC Order in Docket No. ER11-66 dated October 16, 2014.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes:

(1) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 5a

Line No.		(1) 2014 AVERAGE CAPITALIZATION	(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL	(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559 Note 2	46.27%				
2	PREFERRED STOCK	$ 116,842,775	2.14%				
3	COMMON EQUITY	$ 2,820,159,065	51.59%	0.50% Note 1	0.26%	0.26%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399	100.00%		0.26%	0.26%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.26% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate)) / Total Inv. Base)) * Federal Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Federal Corporate Tax Rate; Federal Corporate Tax Rate

6 = ((0.26% + ((0 + 0) / 2,855,230)) * 35.00%)
7 (1 - 35.00%)

8 = 0.1400%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate)) / Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Line 8, Col. (1); Connecticut Corporate Tax Rate; Connecticut Corporate Tax Rate

9 = ((0.26% + ((0 + 0) / 2,855,230) + 0.1400%) * 9.00%)
10 (1 - 9.00%)

11 = 0.0396%

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.4396%

13 INVESTMENT BASE 2,855,230 Line 16, Col. (4)

14 x Cost of Capital Rate 0.4396% Line 12, Col. (1)

15 = Investment Return and Income Taxes $ 12,552 to Sheet 4a, Line 14(4)

Note 1: CAP on ROE incentives per FERC Order in Docket No. EL11-66 dated March 3, 2015.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.

Notes:

(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-217, Schedule 1, Page 2 of 2, Line 18
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 8

Line No.	(A)	(B) Year End		(C) Localized Trans. Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Depreciation Expense							
1	Transmission Depreciation					74,843	Sheet 9, Line 12	(a)
2	General Depreciation	4,980,574	Note 4				FF1 page 336 ln. 10, footnote	(a)
3	*less:* Convex-related General Plant Depreciation Expense	1,110,693					Note 1	(a)
4	Subtotal: General Plant Depr Exp, net of Convex (line 2-3)	3,869,881		0.1023%	Note 2	3,959		(a)
5	Total (line 1+4)					78,802		(a)
6	Amortization of Loss on Reacquired Debt	1,309,927		0.0377%	Note 3	494	FF1 page 117 ln. 64	(a)
7	Amortization of Investment Tax Credits	1,511,975		0.0377%	Note 3	570	FF1 page 266 ln. 8 (f)	(a)
8	Property Taxes	120,836,131		0.0377%	Note 3	45,555	FF1 page 263 ln. 24i & 25i	(a)
	Payroll Tax Expense							
9	Federal Unemployment	5,226					FF1 page 262 ln. 3i, footnote	(a)
10	FICA	233,351					FF1 page 262 ln. 5i, footnote	(a)
11	Medicare	65,613					FF1 page 262 ln. 9i, footnote	(a)
12	CT Unemployment	16,786					FF1 page 262 ln. 15i, footnote	(a)
13	MA Unemployment	(285)					FF1 page 262 ln. 32i, footnote	(a)
14	MA Universal Health	64					FF1 page 262 ln. 33i, footnote	(a)
15	NH Unemployment	1,754					FF1 page 262.1 ln. 4i, footnote	(a)
16	NJ Unemployment	-					FF1 page 262 footnote	(a)
17	DC Unemployment	11					FF1 page 262.1 ln. 14i, footnote	(a)
18	FL Unemployment	1					FF1 page 262.1 ln. 18i, footnote	(a)
19	MI Unemployment	6					FF1 page 262.1 ln. 22i, footnote	(a)
20	NY Unemployment	-					FF1 page 262.1 ln. 10i, footnote	(a)
21	Total (Line 9 to 20)	322,527	Note 4	0.1023%	Note 2	330		
	Transmission Operation and Maintenance							
22	Operation and Maintenance	77,432,007					FF1 page 321 ln. 112	(a)
23	Transmission of Electricity by Others - #565	21,727,966					FF1 page 321 ln. 96	(a)
24	Load Dispatching - #561	-					FF1 page 321 ln. 84	(a)
25	Account 561.1	3,245,594					FF1 page 321 ln. 85	(a)
26	Account 561.2	5,212,556					FF1 page 321 ln. 86	(a)
27	Account 561.3	2,238,612					FF1 page 321 ln. 87	(a)
28	Account 561.4	7,157,291					FF1 page 321 ln. 88	(a)
29	O&M (line 22 - lines 23 to 28)	37,849,988		0.1023%	Note 2	38,721		(a)
	Transmission-related Administrative and General							
30	Administrative and General	37,202,294	Note 4				FF1 page 320 ln. 197 b, footnote	(a)
31	**less**: Property Insurance (#924)	763,857	Note 4				FF1 Page 320 ln. 185 b, footnote	(a)
32	**less**: Regulatory Commission Expenses (#928)	2,749,411	Note 4				FF1 page 320 ln. 189 b, footnote	(a)
33	**less**: General Advertising Expense (#930.1)	10,766	Note 4				FF1 page 320 ln. 191 b, footnote	(a)
34	Subtotal (line 30 - lines 31 to 33)	33,678,260		0.1023%	Note 2	34,453		(a)
35	**plus**: Property Insurance	1,413,419		0.0377%	Note 3	533	FF1 page 323 ln. 185	(a)
36	**plus**: Trans. Regulatory Comm. Exp.	2,749,411		0.1023%	Note 2	2,813	FF1 page 320 ln. 189 b, footnote	(a)
37	**plus**: Trans. Related General Advertising Expense	10,766		0.1023%	Note 2	11	FF1 page 320 ln. 191 b, footnote	(a)
38	**plus**: Trans. Related Public Education Expense	-				-	FF1 page 114 ln. 49, footnote	(a)
39	**plus**: Trans. Merger-Related Costs	18,008,593		0.1023%		18,423	Exhibit No. ES-201, Page 1 of 1, Line 23(H)	(b)
40	Total A&G (sum of lines 34 to 38)	55,860,449				56,233		(b)
41	Transmission Related Taxes and Fees	9,854,673		0.1023%	Note 2	10,081	Note 5	(a)

Note 1: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.
Note 5: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment B.

Notes:

(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Western Massachusetts Electric Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 1a

Line No.	(A)	Attachment I Reference Section:	(B)	(C) Source	(D) Notes
	I. INVESTMENT BASE				
1	Transmission Plant	II(A)(1)(a)	7,316,798	Sheet 2, Line 5	(a)
2	Transmission Plant Held for Future Use	II(A)(1)(b)	-	Sheet 2, Line 6	(a)
3	Accumulated Depreciation	II(A)(1)(c)	290,421	Sheet 2, Line 11	(a)
4	Accumulated Deferred Income Taxes	II(A)(1)(d)	603,776	Sheet 2, Line 12	(a)
5	Loss On Reacquired Debt	II(A)(1)(e)	2,313	Sheet 2, Line 13	(a)
6	Net Investment (Line 1+2-3-4+5)		6,424,914		(a)
7	Prepayments	II(A)(1)(f)	5,502	Sheet 2, Line 14	(a)
8	Materials & Supplies	II(A)(1)(g)	26,259	Sheet 2, Line 15	(a)
9	Cash Working Capital	II(A)(1)(h)	10,266	Sheet 2, Line 22	(b)
10	Total Investment Base (Line 6+7+8+9)		6,466,941		
	II. REVENUE REQUIREMENTS				
11	Investment Return and Income Taxes	II(A)	779,698	Sheet 4a, Line 15(4)	(b)
12	Depreciation Expense	II(B)	184,929	Sheet 8, Line 5	(a)
13	Amortization of Loss on Reacquired Debt	II(C)	323	Sheet 8, Line 6	(a)
14	Investment Tax Credit	II(D)	(154)	Sheet 8, Line 7	(a)
15	Property Tax Expense	II(E)	144,952	Sheet 8, Line 8	(a)
16	Payroll Tax Expense	II(F)	157	Sheet 8, Line 21	(a)
17	Operation & Maintenance Expense	II(G)	54,519	Sheet 8, Line 29	(a)
18	Administrative & General Expense	II(H)	109,729	Sheet 8, Line 39	(b)
19	Support Expenses	II(I)	-		(a)
20	Transmission Related Taxes and Fees	II(J)	177	Sheet 8, Line 40	(a)
21	Total Revenue Requirements (Line 11 thru 20)		1,274,330		(b)

Note:
Investment Return and Income Taxes (line 11 above) was calculated based on the Total Investment Base at 11.07% ROE, plus the Localized PTF Transmission Base (lines 1-3-4) at the .67% capped Incremental ROE.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Western Massachusetts Electric Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 2

Line No.	(A)	(B) Trans. Related Average		(C) Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Transmission Plant							
1	Localized Transmission Plant					7,159,714	Sheet 3, Line 33	(a)
2	Transmission General Plant	18,348,753	Note 4	0.8561%	Note 2	157,084	FF1 page 204 ln. 96, footnote	(a)
3	Total (line 1+2)					7,316,798		(a)
								(a)
								(a)
4	Localized Transmission Plant Held for Future Use					-		
								(a)
	Transmission Accumulated Depreciation							
5	Localized Transmission Accum. Depreciation					256,419	Sheet 9, Line 27(I)	
6	General Plant Accum.Depreciation	3,971,742	Note 4	0.8561%	Note 2	34,002	FF1 page 219 ln. 28, footnote	(a)
7	Total (line 5+6)					290,421		(a)
8								(a)
								(a)
								(a)
9	Transmission Accumulated Deferred Taxes					603,776	Sheet 10, Line 46	
10	Unam. Loss on Reacquired Debt (189)	533,928		0.4332%	Note 3	2,313	FF1 page 111 ln. 81	(a)
								(a)
11	Transmission Prepayments (165)	642,737	Note 4	0.8561%	Note 2	5,502	FF1 page 110 ln. 57, footnote	
12	Transmission Materials and Supplies	3,067,304		0.8561%	Note 2	26,259	FF1 page 227 ln. 8	(a)
								(a)
	Cash Working Capital							
13	Localized Operation & Maintenance Expense					54,519	Sheet 8, Line 28	(a)
14	Localized Administrative & General Expense					109,729	Sheet 8, Line 39	(b)
15	Subtotal (line 13+14)					164,248		(b)
16	12.5% allowance					0.125	x 45 / 360	(a)
17	Total current Year End (line 15*16)					20,531		(b)
18	Prior Year End Cash Working Capital					-		(a)
19	Average Cash Working Capital [(line 17+18)/2]					10,266		(b)

Note 1: Reflects actual information per Eversource's accounting records.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.

Notes:

(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Western Massachusetts Electric Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 4a

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 568,072,183	Note 2	49.54%	4.31%	Note 2	2.14%		
2	PREFERRED STOCK	$ -		0.00%	0.00%		0.00%	0.00%	
3	COMMON EQUITY	$ 578,634,319		50.46%	11.07%	Note 1	5.59%	5.59%	
4	TOTAL INVESTMENT RETURN	$ 1,146,706,502		100.00%			7.73%	5.59%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 7.73% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) / (1) + Eq. AFUDC of Deprec. Exp. / (1 - Federal Income Tax Rate)) / Total Inv. Base)) * Federal Income Tax Rate)

Source: Line 4, Col. (5); Sheet 8, Line 7; Sheet 6, Line 1; Sheet 1, Line 10; Federal Corporate Tax Rate

6 = ((5.59% + (((154) + 1,593) / Federal Corporate Tax Rate) / 6,466,941)) * 35.00%)

7 (1 - 35.00%)

8 = 3.0220%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) / (1) + Eq. AFUDC of Deprec. Exp. / (1 - State Income Tax Rate)) / Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)

Source: Line 4, Col. (5); Sheet 8, Line 7; Sheet 6, Line 1; Sheet 1, Line 10; Line 8, Col. (1); Massachusetts Corporate Tax Rate

9 = ((5.59% + (((154) + 1,593) / 6,466,941) + 3.0220%) * 8.00%)

10 (1 - 8.00%) Massachusetts Corporate Tax Rate

11 = 0.7508%

12 (a)+(b)+(c) **Cost of Capital Rate** = 11.5028%

Line			
13	INVESTMENT BASE	6,466,941	Sheet 1, Line 10
14			
15	x Cost of Capital Rate	11.5028%	Line 12, Col. (1)
16	= Investment Return and Income Taxes	$ 743,879	

Total Investment Return and Income Taxes			
@11.07%	$	743,879	Line 16, Col. (1)
@.67%	$	35,819	Sheet 5, Line 17
	$	779,698	To Sheet 1a, Line 11

Note 1: ROE per FERC Order in Docket No. ER04-157 dated March 24, 2008.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes:

(1) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Western Massachusetts Electric Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 568,072,183	Note 2	49.54%					
2	PREFERRED STOCK	$ -		0.00%					
3	COMMON EQUITY	$ 578,634,319		50.46%	0.50%	Note 1	0.25%	0.25%	
4	TOTAL INVESTMENT RETURN	$ 1,146,706,502		100.00%			0.25%	0.25%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.25% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate) Total Inv. Base)) * Federal Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Federal Corporate Tax Rate

6 = ((0.25% + ((0 + 0) / 6,466,941)) * 35.00%)
7 (1 - 35.00%) Federal Corporate Tax Rate

8 = 0.1346%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate) Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Line 8, Col. (1); Massachusetts Corporate Tax Rate

9 = ((0.25% + ((0 + 0) / 6,466,941) + 0.1346%) * 8.00%)
10 (1 - 8.00%) Massachusetts Corporate Tax Rate

11 = 0.0334%

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.4180%

13	INVESTMENT BASE	6,466,941	Line 16, Col. (4)
14	x Cost of Capital Rate	0.4180%	Line 12, Col. (1)
15	= Investment Return and Income Taxes	$ 27,032	to Sheet 4a, Line 14(4)

Note 1: CAP on ROE incentives per FERC Order in Docket No. EL11-66 dated March 3, 2015.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.

Notes:
(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-217, Schedule 1, Page 2 of 2, Line 18
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Western Massachusetts Electric Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 8

Line No.	(A)	(B) Year End		(C) Localized Trans. Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Depreciation Expense							
1	Transmission Depreciation					178,169	Sheet 9, Line 29	(a)
2	General Depreciation	789,658	Note 4	0.8561%	Note 2	6,760	FF1 page 336 ln. 10, footnote	(a)
3	Total (line 1+4)					184,929		(a)
4								(a)
								(a)
5	Amortization of Loss on Reacquired Debt	74,501		0.4332%	Note 3	323	FF1 pg 117 ln. 64	
								(a)
6	Amortization of Investment Tax Credits	35,604		0.4332%	Note 3	154	FF1 page 266 ln. 8(f), footnote	
								(a)
7	Property Taxes	33,460,690		0.4332%	Note 3	144,952	FF1 page 263 ln. 31i & 32i	
								(a)
	Payroll Tax Expense							
8	Federal Unemployment	283					FF1 page 262 ln. 3i, footnote	
9	FICA	13,202					FF1 page 262 ln. 5i, footnote	(a)
10	Medicare	3,757					FF1 page 262 ln. 9i, footnote	(a)
11	CT Unemployment	852					FF1 page 262 ln. 13i, footnote	(a)
12	MA Unemployment	69					FF1 page 262 ln. 22i, footnote	(a)
13	MA Universal Health	19					FF1 page 262 ln. 27i, footnote	(a)
14	NH Unemployment	108					FF1 page 262 ln. 37i, footnote	(a)
15	NJ Unemployment	-					FF1 page 262, footnote	(a)
16	DC Unemployment	1					FF1 page 262.1 ln. 6i, footnote	(a)
17	FL Unemployment	-					FF1 page 262, footnote	(a)
18	MI Unemployment	-					FF1 page 262, footnote	(a)
19	NY Unemployment	-					FF1 page 262, footnote	(a)
20	Total (Line 9 to 20)	18,291	Note 4	0.8561%	Note 2	157		(a)
	Transmission Operation and Maintenance							
21	Operation and Maintenance	20,725,279					FF1 page 321 ln. 112	
22	Transmission of Electricity by Others - #565	13,174,678					FF1 page 321 ln. 96	(a)
23	Load Dispatching - #561	-					FF1 page 321 ln. 84	(a)
24	Account 561.1	12,368					FF1 page 321 ln. 85	(a)
25	Account 561.2	50,569					FF1 page 321 ln. 86	(a)
26	Account 561.3	13,262					FF1 page 321 ln. 87	(a)
27	Account 561.4	1,106,108					FF1 page 321 ln. 88	(a)
28	O&M (line 22 - lines 23 to 28)	6,368,294		0.8561%	Note 2	54,519		(a)
								(a)
	Transmission-related Administrative and General							
29	Administrative and General	8,041,502	Note 4				FF1 page 320 ln. 197, footnote	(a)
30	less: Property Insurance (#924)	106,141	Note 4				FF1 Page 320 ln. 185 b, footnote	(a)
31	less: Regulatory Commission Expenses (#928)	563,123	Note 4				FF1 page 320 ln. 189 b, footnote	(a)
32	less: General Advertising Expense (#930.1)	2,857	Note 4				FF1 page 320 ln. 191 b, footnote	(a)
33	Subtotal (line 30 - lines 31 to 33)	7,369,381		0.8561%	Note 2	63,089		(a)
34	plus: Property Insurance	248,747		0.4332%	Note 3	1,078	FF1 page 323 ln. 185	(a)
35	plus: Trans. Regulatory Comm. Exp.	563,123		0.8561%	Note 2	4,821	FF1 page 320 ln. 189 b, footnote	(a)
36	plus: Trans. Related General Advertising Expense	2,857		0.8561%	Note 2	24	FF1 page 320 ln. 191 b, footnote	(a)
37	plus: Trans. Related Public Education Expense	-				-	FF1 page 114 ln. 49, footnote	(a)
38	plus: Trans. Merger-Related Costs	4,756,064		0.8561%		40,717	Exhibit No. ES-201, Page 1 of 1, Line 26(H)	(b)
39	Total A&G (sum of lines 33 to 38)	12,940,172				109,729		(b)
40	Transmission Related Taxes and Fees	20,627		0.8561%	Note 2	177	Note 5	
								(a)

Note 1: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.
Note 5: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment B.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Exhibit No. ES-220

Calculation of Carrying Charges, Amortization and Unamortized balances

Eversource Energy Service Company

The Connecticut Light & Power Company
Calculation of Unamortized Balance in FERC Account 182.3
and Associated Annual Amortization

Line	(A) Item	(B) 2016		(C) 2017	(D) 2018
1	Beg. Balance (PY line 3)	$ 21,459,977	(a),(b)	$ 14,306,651	$ 7,153,326
2	Amortization (line 7 / 3 years)	$ 7,153,326		$ 7,153,326	$ 7,153,326
3	End Balance (line 1 - 2)	$ 14,306,651		$ 7,153,326	$ -
4	BOY\EOY Average ([Line 1 + line 3] / 2)	$ 7,153,326	(c)	$ 10,729,989	$ 3,576,663

Notes:

(a)

Line	Item	Amount	Source
5	Merger Costs by OpCo	$ 18,008,593	Exhibit No. ES-220, Page 5 of 8, Line 36(C)
6	Carrying Charge	$ 3,451,384	Exhibit No. ES-220, Page 5 of 8, Line 37(C)
7	Total Merger Costs with CC (line 5 + 6)	$ 21,459,977	

(b) The unamortized balance is not effective until June 1, 2016. Therefore the actual beginning balance in 2016 is zero. The amount shown on Line 1 for 2016 is for illustrative purposes only to get the 2016 ending balance.

(c) Uses the average of a beginning balance of zero, and the ending balance on Line 3. See note (b) above

NSTAR Electric Company
Calculation of Unamortized Balance in FERC Account 182.3
and Associated Annual Amortization

Line	(A) Item		(B) 2016			(C) 2017		(D) 2018
1	Beg. Balance (PY line 3)	$	11,430,585	(a)	$	7,620,390	$	3,810,195
2	Amortization (line 6 / 3 years)	$	3,810,195		$	3,810,195	$	3,810,195
3	End Balance (line 1 - 2)	$	7,620,390		$	3,810,195	$	-

Notes:

(a)

4	Merger Costs by OpCo	$	10,517,524	Exhibit No. ES-220, Page 6 of 8, Line 36(C)
5	Carrying Charge	$	913,061	Exhibit No. ES-220, Page 6 of 8, Line 37(C)
6	Total Merger Costs with CC (line 4 + 5)	$	11,430,585	

Public Service Company of New Hampshire
Calculation of Unamortized Balance in FERC Account 182.3
and Associated Annual Amortization

Line	(A) Item	(B) 2016		(C) 2017	(D) 2018
1	Beg. Balance (PY line 3)	$ 4,444,867	(a),(b)	$ 2,963,245	$ 1,481,622
2	Amortization (line 7 / 3 years)	$ 1,481,622		$ 1,481,622	$ 1,481,622
3	End Balance (line 1 - 2)	$ 2,963,245		$ 1,481,622	$ -
4	BOY\EOY Average ([Line 1 + line 3] / 2)	$ 1,481,622	(c)	$ 2,222,434	$ 740,811

Notes:

(a)

5	Merger Costs by OpCo	$ 4,073,625	Exhibit No. ES-220, Page 7 of 8, Line 36(C)
6	Carrying Charge	$ 371,242	Exhibit No. ES-220, Page 7 of 8, Line 37(C)
7	Total Merger Costs with CC (line 5 + 6)	$ 4,444,867	

(b) The unamortized balance is not effective until June 1, 2016. Therefore the actual beginning balance in 2016 is zero. The amount shown on Line 1 for 2016 is for illustrative purposes only to get the 2016 ending balance.

(c) Uses the average of a beginning balance of zero, and the ending balance on Line 3. See note (b) above

Line	(A) Item	(B) 2016		(C) 2017	(D) 2018
1	Beg. Balance (PY line 3)	$ 5,829,628	(a),(b)	$ 3,886,419	$ 1,943,209
2	Amortization (line 7 / 3 years)	$ 1,943,209		$ 1,943,209	$ 1,943,209
3	End Balance (line 1 - 2)	$ 3,886,419		$ 1,943,209	$ -
4	BOY\EOY Average ([Line 1 + line 3] / 2)	$ 1,943,209	(c)	$ 2,914,814	$ 971,605

Notes:

(a)

5	Merger Costs by OpCo	$ 4,756,064	Exhibit No. ES-220, Page 8 of 8, Line 36(C)
6	Carrying Charge	$ 1,073,564	Exhibit No. ES-220, Page 8 of 8, Line 37(C)
7	Total Merger Costs with CC (line 5 + 6)	$ 5,829,628	

(b) The unamortized balance is not effective until June 1, 2016. Therefore the actual beginning balance in 2016 is zero. The amount shown on Line 1 for 2016 is for illustrative purposes only to get the 2016 ending balance.

(c) Uses the average of a beginning balance of zero, and the ending balance on Line 3. See note (b) above

The Connecticut Light and Power Company
Calculation of Carrying Charges on the Merger related Transmission Costs

Line	(A) Date	(B) Current Year End Balance		(C) Cumulative Balance	(D) No. Of Days	(E) Carrying Charge Rate (g)	(F) = (C)*(D)/#of days*(E) Annual Carrying Charge	(G) = (F)+Prior Period (G) Cumulative Carrying Charges	Notes
1	12/31/2010	$2,547,288	(a)	$2,547,288	0	8.58%	$0	$0	(h)
2					0				
3	*Semi-Annual Cumulative Amount with Interest*			$2,547,288					
4	1/1/2011			$2,547,288	181	8.58%	$108,380	$108,380	
5	6/30/2011				181				
6	*Semi-Annual Cumulative Amount with Interest*			$2,655,668					
7	7/1/2011			$2,655,668	184	8.58%	$114,865	$223,245	
8	12/31/2011	$3,933,627	(b)		184				
9	*Semi-Annual Cumulative Amount with Interest*			$6,704,160					
10	1/1/2012			$6,704,160	182	3.65%	$121,682	$344,927	
11	6/30/2012				182				
12	*Semi-Annual Cumulative Amount with Interest*			$6,825,842					
13	7/1/2012			$6,825,842	184	3.65%	$125,595	$470,522	
14	12/31/2012	$7,341,270	(c)		184				
15	*Semi-Annual Cumulative Amount with Interest*			$14,292,707					
16	1/1/2013			$14,292,707	181	3.76%	$266,494	$737,016	
17	6/30/2013				181				
18	*Semi-Annual Cumulative Amount with Interest*			$14,559,201					
19	7/1/2013			$14,559,201	184	3.76%	$275,963	$1,012,979	
20	12/31/2013	$2,294,272	(d)		184				
21	*Semi-Annual Cumulative Amount with Interest*			$17,129,436					
22	1/1/2014			$17,129,436	181	3.57%	$303,247	$1,316,226	
23	6/30/2014				181				
24	*Semi-Annual Cumulative Amount with Interest*			$17,432,683					
25	7/1/2014			$17,432,683	184	3.57%	$313,731	$1,629,957	
26	12/31/2014	$1,764,323	(e)		184				
27	*Semi-Annual Cumulative Amount with Interest*			$19,510,737					
28	1/1/2015			$19,510,737	181	6.39%	$618,244	$2,248,201	
29	6/30/2015				181				
30	*Semi-Annual Cumulative Amount with Interest*			$20,128,981					
31	7/1/2015			$20,128,981	184	6.39%	$648,407	$2,896,608	
32	12/31/2015	$127,813	(f)		184				
33	*Semi-Annual Cumulative Amount with Interest*			$20,905,201					
34	1/1/2016			$20,905,201	152	6.39%	$554,776	$3,451,384	
35	5/31/2016				152				

Line		Amount
36	Principal	$ 18,008,593
37	Interest	$ 3,451,384
38	Total	$ 21,459,977

Notes:

(a) Exhibit No. ES-201, Page 1 of 1, Line 23(B)
(b) Exhibit No. ES-201, Page 1 of 1, Line 23(C)
(c) Exhibit No. ES-201, Page 1 of 1, Line 23(D)
(d) Exhibit No. ES-201, Page 1 of 1, Line 23(E)
(e) Exhibit No. ES-201, Page 1 of 1, Line 23(F)
(f) Exhibit No. ES-201, Page 1 of 1, Line 23(G)
(g) Average Monthly AFUDC rates used for 2012-2015. 2015 AFUDC rate is used for January - May 2016.
(h) No Carrying Charges accrued in 2010 because all costs for each year are assumed to be incurred at the end of the year.

NSTAR Electric Company
Calculation of Carrying Charges on the Merger related Transmission Costs

Line	(A) Date	(B) Current Year End Balance		(C) Cumulative Balance	(D) No. Of Days	(E) Carrying Charge Rate (g)	(F) = (C)*(D)/#of days*(E) Annual Carrying Charge	(G) = (F)+Prior Period (G) Cumulative Carrying Charges	Notes
1	12/31/2010	$1,499,702	(a)	$1,499,702	0	1.17%	$0	$0	(h)
2					0				
3	*Semi-Annual Cumulative Amount with Interest*			$1,499,702					
4	1/1/2011			$1,499,702	181	0.71%	$5,293	$5,293	
5	6/30/2011				181				
6	*Semi-Annual Cumulative Amount with Interest*			$1,504,995					
7	7/1/2011			$1,504,995	184	0.71%	$5,400	$10,693	
8	12/31/2011	$2,193,786	(b)		184				
9	*Semi-Annual Cumulative Amount with Interest*			$3,704,181					
10	1/1/2012			$3,704,181	182	0.40%	$7,368	$18,061	
11	6/30/2012				182				
12	*Semi-Annual Cumulative Amount with Interest*			$3,711,549					
13	7/1/2012			$3,711,549	184	0.40%	$7,484	$25,545	
14	12/31/2012	$4,359,312	(c)		184				
15	*Semi-Annual Cumulative Amount with Interest*			$8,078,345					
16	1/1/2013			$8,078,345	181	0.50%	$20,030	$45,575	
17	6/30/2013				181				
18	*Semi-Annual Cumulative Amount with Interest*			$8,098,375					
19	7/1/2013			$8,098,375	184	0.50%	$20,412	$65,987	
20	12/31/2013	$1,350,740	(d)		184				
21	*Semi-Annual Cumulative Amount with Interest*			$9,469,527					
22	1/1/2014			$9,469,527	181	2.41%	$113,170	$179,157	
23	6/30/2014				181				
24	*Semi-Annual Cumulative Amount with Interest*			$9,582,697					
25	7/1/2014			$9,582,697	184	2.41%	$116,421	$295,578	
26	12/31/2014	$1,038,735	(e)		184				
27	*Semi-Annual Cumulative Amount with Interest*			$10,737,853					
28	1/1/2015			$10,737,853	181	3.98%	$211,927	$507,505	
29	6/30/2015				181				
30	*Semi-Annual Cumulative Amount with Interest*			$10,949,780					
31	7/1/2015			$10,949,780	184	3.98%	$219,692	$727,197	
32	12/31/2015	$75,249	(f)		184				
33	*Semi-Annual Cumulative Amount with Interest*			$11,244,721					
34	1/1/2016			$11,244,721	152	3.98%	$185,864	$913,061	
35	5/31/2016				152				

Line		Amount
36	Principal	$ 10,517,524
37	Interest	$ 913,061
38	Total	$ 11,430,585

Notes:
(a) Exhibit No. ES-201, Page 1 of 1, Line 24(B)
(b) Exhibit No. ES-201, Page 1 of 1, Line 24(C)
(c) Exhibit No. ES-201, Page 1 of 1, Line 24(D)
(d) Exhibit No. ES-201, Page 1 of 1, Line 24(E)
(e) Exhibit No. ES-201, Page 1 of 1, Line 24(F)
(f) Exhibit No. ES-201, Page 1 of 1, Line 24(G)
(g) Average Monthly AFUDC rates used for 2012-2015. 2015 AFUDC rate is used for January - May 2016.
(h) No Carrying Charges accrued in 2010 because all costs for each year are assumed to be incurred at the end of the year.

Public Service Company of New Hampshire
Calculation of Carrying Charges on the Merger related Transmission Costs

Line	(A) Date	(B) Current Year End Balance		(C) Cumulative Balance	(D) No. Of Days	(E) Carrying Charge Rate (g)	(F) = (C)*(D)/#of days*(E) Annual Carrying Charge	(G) = (F)+Prior Period (G) Cumulative Carrying Charges	Notes
1	12/31/2010	$577,091	(a)	$577,091	0	7.24%	$0	$0	(h)
2					0				
3	*Semi-Annual Cumulative Amount with Interest*			$577,091					
4	1/1/2011			$577,091	181	7.82%	$22,379	$22,379	
5	6/30/2011				181				
6	*Semi-Annual Cumulative Amount with Interest*			$599,470					
7	7/1/2011			$599,470	184	7.82%	$23,632	$46,011	
8	12/31/2011	$887,324	(b)		184				
9	*Semi-Annual Cumulative Amount with Interest*			$1,510,426					
10	1/1/2012			$1,510,426	182	5.95%	$44,690	$90,701	
11	6/30/2012				182				
12	*Semi-Annual Cumulative Amount with Interest*			$1,555,116					
13	7/1/2012			$1,555,116	184	5.95%	$46,645	$137,346	
14	12/31/2012	$1,660,775	(c)		184				
15	*Semi-Annual Cumulative Amount with Interest*			$3,262,536					
16	1/1/2013			$3,262,536	181	1.31%	$21,194	$158,540	
17	6/30/2013				181				
18	*Semi-Annual Cumulative Amount with Interest*			$3,283,730					
19	7/1/2013			$3,283,730	184	1.31%	$21,685	$180,225	
20	12/31/2013	$519,770	(d)		184				
21	*Semi-Annual Cumulative Amount with Interest*			$3,825,185					
22	1/1/2014			$3,825,185	181	2.07%	$39,265	$219,490	
23	6/30/2014				181				
24	*Semi-Annual Cumulative Amount with Interest*			$3,864,450					
25	7/1/2014			$3,864,450	184	2.07%	$40,326	$259,816	
26	12/31/2014	$399,709	(e)		184				
27	*Semi-Annual Cumulative Amount with Interest*			$4,304,485					
28	1/1/2015			$4,304,485	181	1.81%	$38,635	$298,451	
29	6/30/2015				181				
30	*Semi-Annual Cumulative Amount with Interest*			$4,343,120					
31	7/1/2015			$4,343,120	184	1.81%	$39,628	$338,079	
32	12/31/2015	$28,956	(f)		184				
33	*Semi-Annual Cumulative Amount with Interest*			$4,411,704					
34	1/1/2016			$4,411,704	152	1.81%	$33,163	$371,242	
35	5/31/2016				152				

Line		Amount
36	Principal	$ 4,073,625
37	Interest	$ 371,242
38	Total	$ 4,444,867

Notes:
(a) Exhibit No. ES-201, Page 1 of 1, Line 25(B)
(b) Exhibit No. ES-201, Page 1 of 1, Line 25(C)
(c) Exhibit No. ES-201, Page 1 of 1, Line 25(D)
(d) Exhibit No. ES-201, Page 1 of 1, Line 25(E)
(e) Exhibit No. ES-201, Page 1 of 1, Line 25(F)
(f) Exhibit No. ES-201, Page 1 of 1, Line 25(G)
(g) Average Monthly AFUDC rates used for 2012-2015. 2015 AFUDC rate is used for January - May 2016.
(h) No Carrying Charges accrued in 2010 because all costs for each year are assumed to be incurred at the end of the year.

Western Massachusetts Electric Company
Calculation of Carrying Charges on the Merger related Transmission Costs

Line	(A) Date	(B) Current Year End Balance		(C) Cumulative Balance	(D) No. Of Days	(E) Carrying Charge Rate (g)	(F) = (C)*(D)/#of days*(E) Annual Carrying Charge	(G) = (F)+Prior Period (G) Cumulative Carrying Charges	Notes
1	12/31/2010	$685,526	(a)	$685,526	0	5.94%	$0	$0	(h)
2					0				
3	*Semi-Annual Cumulative Amount with Interest*			$685,526					
4	1/1/2011			$685,526	181	7.39%	$25,122	$25,122	
5	6/30/2011				181				
6	*Semi-Annual Cumulative Amount with Interest*			$710,648					
7	7/1/2011			$710,648	184	7.39%	$26,474	$51,596	
8	12/31/2011	$975,948	(b)		184				
9	*Semi-Annual Cumulative Amount with Interest*			$1,713,070					
10	1/1/2012			$1,713,070	182	6.96%	$59,289	$110,885	
11	6/30/2012				182				
12	*Semi-Annual Cumulative Amount with Interest*			$1,772,359					
13	7/1/2012			$1,772,359	184	6.96%	$62,185	$173,070	
14	12/31/2012	$1,967,945	(c)		184				
15	*Semi-Annual Cumulative Amount with Interest*			$3,802,489					
16	1/1/2013			$3,802,489	181	6.22%	$117,285	$290,355	
17	6/30/2013				181				
18	*Semi-Annual Cumulative Amount with Interest*			$3,919,774					
19	7/1/2013			$3,919,774	184	6.22%	$122,907	$413,262	
20	12/31/2013	$617,434	(d)		184				
21	*Semi-Annual Cumulative Amount with Interest*			$4,660,115					
22	1/1/2014			$4,660,115	181	5.94%	$137,268	$550,530	
23	6/30/2014				181				
24	*Semi-Annual Cumulative Amount with Interest*			$4,797,383					
25	7/1/2014			$4,797,383	184	5.94%	$143,653	$694,183	
26	12/31/2014	$474,814	(e)		184				
27	*Semi-Annual Cumulative Amount with Interest*			$5,415,850					
28	1/1/2015			$5,415,850	181	4.83%	$129,718	$823,901	
29	6/30/2015				181				
30	*Semi-Annual Cumulative Amount with Interest*			$5,545,568					
31	7/1/2015			$5,545,568	184	4.83%	$135,026	$958,927	
32	12/31/2015	$34,397	(f)		184				
33	*Semi-Annual Cumulative Amount with Interest*			$5,714,991					
34	1/1/2016			$5,714,991	152	4.83%	$114,637	$1,073,564	
35	5/31/2016				152				

Line		Amount
36	Principal	$ 4,756,064
37	Interest	$ 1,073,564
38	Total	$ 5,829,628

Notes:
(a) Exhibit No. ES-201, Page 1 of 1, Line 26(B)
(b) Exhibit No. ES-201, Page 1 of 1, Line 26(C)
(c) Exhibit No. ES-201, Page 1 of 1, Line 26(D)
(d) Exhibit No. ES-201, Page 1 of 1, Line 26(E)
(e) Exhibit No. ES-201, Page 1 of 1, Line 26(F)
(f) Exhibit No. ES-201, Page 1 of 1, Line 26(G)
(g) Average Monthly AFUDC rates used for 2012-2015. 2015 AFUDC rate is used for January - May 2016.
(h) No Carrying Charges accrued in 2010 because all costs for each year are assumed to be incurred at the end of the year.

Exhibit No. ES-221
Schedule 1

Summary of Impact on CL&P's, PSNH's and WMECO's PTF Revenue Requirements under Attachment F of ISO-NE OATT (3-year amortization)

Eversource Energy Service Company

CL&P, PSNH and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirement Comparison Under Present and Changed Rates
Under Attachment F of the ISO-NE OATT
For the Calendar Years 2016-2018

	(A)	(B)		(C)		(D) = (C) - (B)	(E) = (D) / (B)
Line	Description	Total PTF Revenue Requirements		Total PTF Revenue Requirements Including Merger-Related Costs		Difference (5) (Rounded to '000s)	% Difference
1	2016 Estimated PTF Revenue Requirement	$ 767,938,495	(1)	$ 779,831,223	(2)	$ 11,893,000	1.5%
2	2017 Estimated PTF Revenue Requirement	$ 767,938,495	(1)	$ 778,684,568	(3)	$ 10,746,000	1.4%
3	2018 Estimated PTF Revenue Requirement	$ 767,938,495	(1)	777,537,521	(4)	$ 9,599,000	1.2%

Notes:

(1) Exhibit No. ES-221, Schedule 2, Page 1 of 20, Line 10(F)
(2) Exhibit No. ES-221, Schedule 3, Page 1 of 20, Line 10(F)
(3) Exhibit No. ES-221, Schedule 4, Page 1 of 20, Line 14(F)
(4) Exhibit No. ES-221, Schedule 5, Page 1 of 20, Line 18(F)
(5) In connection with the three-year amortization alternative (with the proposed effective date of June 1, 2016), Eversource is showing the revenue impact for the thirty-six month period June 1, 2016 through May 31, 2019. Eversource is using calendar year revenue requirement calculations as estimates for the thirty-six month period beginning June 1, 2016. See Cooper Testimony Exhibit No. ES-200.

	2016	2017	2018	2019	Total
The amounts for each year are as follows:	$ 6,938,000	$ 11,224,000	$ 10,077,000	$ 4,000,000	$ 32,239,000

Exhibit No. ES-221
Schedule 2

CL&P's, PSNH's and WMECO's PTF Revenue Requirements under the Present Rates

Eversource Energy Service Company

CL&P, PSNH and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Present Rates
Under Attachment F of the ISO-NE OATT
For the Calendar Years 2016-2018

Line	(A) Description	(B) Reference	(C) CL&P	(D) PSNH	(E) WMECO	(F)=(C)+(D)+(E) Total
1	2014 Actual PTF Revenue Requirements		$ 454,159,787 (1)	$ 107,956,641 (2)	$ 110,031,567 (3)	$ 672,147,995
2	Estimated 2015 PTF Plant Additions	(4)	$ 276,000,000	$ 114,000,000	$ 87,000,000	$ 477,000,000
3	Carrying Charge Factor (CCF)	Exhibit No. ES-221, Schedule 2, Page 3 of 20, Note (3)	15.25%	16.55%	14.00%	
4	2015 Incremental Estimated PTF Revenue Requirements	Line 2 x 3	42,090,000	18,867,000	12,180,000	$ 73,137,000
5	2015 Incremental Estimated PTF CWIP Rev. Req.	(4)	$ (19,400,000)	$ -	$ -	$ (19,400,000)
6	Total Estimated PTF Revenue Requirement for 2015	Line 1 + 4 + 5	$ 476,849,787	$ 126,823,641	$ 122,211,567	$ 725,884,995
7	Estimated 2016 PTF Plant Additions	(4)	$ 68,000,000	$ 117,000,000	$ 88,000,000	$ 273,000,000
8	Carrying Charge Factor (CCF)	Line 3	15.25%	16.55%	14.00%	
9	2016 Incremental Estimated PTF Revenue Requirements	Line 7 x 8	10,370,000	19,363,500	12,320,000	$ 42,053,500
10	Total Estimated PTF Revenue Requirement for 2016	Line 6 + 9	$ 487,219,787	$ 146,187,141	$ 134,531,567	$ 767,938,495 (5)

Notes:
(1) Exhibit No. ES-221: Schedule 2, Page 2 of 20, LN. 29(B) + Schedule 2, Page 3 of 20, LN. 29(B) + Schedule 2, Page 4 of 20, LN. 5(B) + Schedule 2, Page 5 of 20, LN. 9(B)
(2) Exhibit No. ES-221: Schedule 2, Page 2 of 20, LN. 29(C) + Schedule 2, Page 3 of 20, LN. 29(C) + Schedule 2, Page 4 of 20, LN. 5(C)
(3) Exhibit No. ES-221: Schedule 2, Page 2 of 20, LN. 29(D) + Schedule 2, Page 3 of 20, LN. 29(D) + Schedule 2, Page 4 of 20, LN. 5(D) + Schedule 2, Page 5 of 20, LN. 9(C)
(4) Based on Eversource's Forecast
(5) The revenue requirements calculations for the calendar year 2016 (including any forecast for 2016) are used as an estimate for the revenue requirements for 2017 and 2018, which are used to calculate the revenue impact of the proposed cost recovery.

CL&P, PSNH and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Present Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Pre-1997
Worksheet 1A

		(A)		(B)	(C)	(D)	(E)=(B)+(C)+(D)	(F)	(G)
Line	I.	INVESTMENT BASE	Attachment F Reference Section:	CL&P	PSNH	WMECO	Total	Reference	Notes
1		Transmission Plant	(A)(1)(a)	358,812,326	88,564,672	53,145,202	500,522,200	W/S 3A,3B,3C line 1	(1)
2		General Plant	(A)(1)(b)	12,027,048	7,336,167	1,150,391	20,513,606	W/S 3A,3B,3C line 2	(1)
3		Plant Held For Future Use	(A)(1)(c)	84,157	1,138,376	0	1,222,533	W/S 3A,3B,3C line 4	(1)
4		Total Plant (Lines 1+2+3)		370,923,531	97,039,215	54,295,593	522,258,339		(1)
5		Accumulated Depreciation	(A)(1)(d)	73,042,167	17,223,185	3,590,105	93,855,457	W/S 3A,3B,3C line 7	(1)
6		Accumulated Deferred Income Taxes	(A)(1)(e)	49,105,827	16,884,906	13,484,433	79,475,166	W/S 3A,3B,3C line 10	(1)
7		Loss On Reacquired Debt	(A)(1)(f)	623,759	245,415	20,268	889,442	W/S 3A,3B,3C line 11	(1)
8		Other Regulatory Assets	(A)(1)(g)	2,278,427	1,052,873	568,906	3,900,206	W/S 3A,3B,3C line 15	(2)
9		Net Investment (Line 4-5-6+7+8)		251,677,723	64,229,412	37,810,229	353,717,364		(2)
10		Prepayments	(A)(1)(h)	1,885,610	662,602	62,672	2,610,884	W/S 3A,3B,3C line 16	(1)
11		Materials & Supplies	(A)(1)(i)	4,547,780	1,261,158	192,426	6,001,364	W/S 3A,3B,3C line 17	(1)
12		Cash Working Capital	(A)(1)(j)	1,080,762	381,944	154,988	1,617,694	W/S 3A,3B,3C line 23	(2)
13		Total Investment Base (Line 9+10+11+12)		259,191,875	66,535,116	38,220,315	363,947,306		(2)
	II.	REVENUE REQUIREMENTS							
14		Investment Return and Income Taxes	(A)	32,224,548	7,926,262	4,390,482	44,541,292	W/S 2A,2B,2C, line 15	(2)
15		Depreciation Expense	(B)	8,594,771	1,919,255	1,026,040	11,540,066	W/S 4A,4B,4C line 3	(1)
16		Amortization of Loss on Reacquired Debt	(C)	68,393	30,531	3,040	101,964	W/S 4A,4B,4C line 4	(1)
17		Investment Tax Credit	(D)	(49,341)	(600)	(2,179)	(52,120)	W/S 4A,4B,4C line 5	(1)
18		Property Tax Expense	(E)	5,226,750	2,236,785	1,145,707	8,609,242	W/S 4A,4B,4C line 8	(1)
19		Payroll Tax Expense	(F)	37,155	(505)	1,120	37,770	W/S 4A,4B,4C line 18	(1)
20		Operation & Maintenance Expense	(G)	4,360,357	1,271,570	389,810	6,021,737	W/S 4A,4B,4C line 16	(1)
21		Administrative & General Expense	(H)	4,285,741	1,279,710	492,228	6,057,679	W/S 4A,4B,4C line 17	(2)
22		Transmission Related Integrated Facilities Charge	(I)	-	-	-	-	N/A	(1)
23		Transmission Support Revenue	(J)	(2,917,925)	(376,198)	-	(3,294,123)	W/S 7	(1)
24		Transmission Support Expense	(K)	1,625,568	880,469	357,869	2,863,906	W/S 7	(1)
25		Transmission Related Expense from Generators	(L)	-	-	-	-	N/A	(1)
26		Transmission Related Taxes and Fees Charge	(M)	1,135,268	19,553	1,263	1,156,084	Attachment B, line 14	(1)
27		Revenue for ST Trans. Service Under the OATT	(N)	(68,394)	(16,040)	(8,880)	(93,314)	Attachment C, line 9	(1)
28		Transmission Rents Received from Electric Property	(O)	(5,239,993)	(1,821,957)	(402,030)	(7,463,980)	Attachment C1, line 3	(1)
29		Total Revenue Requirements (Line 14 thru 28)		49,282,898	13,348,835	7,394,470	70,026,203		(2)

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.

(2) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000. Provided this support because these balances will be revised under the changed rates.

CL&P, PSNH and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Present Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Post-1996
Worksheet 1B

Line		(A)	Attachment F Reference Section:	(B) CL&P	(C) PSNH	(D) WMECO	(E)=(B)+(C)+(D) Total	(F) Reference	(G) Notes
	I.	INVESTMENT BASE							
1		Transmission Plant	(A)(1)(a)	2,415,403,244	568,289,707	717,553,491	3,701,246,442	W/S 3A,3B,3C line 1	(1)
2		General Plant	(A)(1)(b)	80,962,316	47,073,591	15,532,275	143,568,182	W/S 3A,3B,3C line 2	(1)
3		Plant Held For Future Use	(A)(1)(c)	566,521	7,304,557	-	7,871,078	W/S 3A,3B,3C line 4	(1)
4		Total Plant (Lines 1+2+3)		2,496,932,081	622,667,855	733,085,766	3,852,685,702		(1)
5		Accumulated Depreciation	(A)(1)(d)	491,696,956	110,515,089	48,472,669	650,684,714	W/S 3A,3B,3C line 7	(1)
6		Accumulated Deferred Income Taxes	(A)(1)(e)	330,565,024	108,344,471	182,063,297	620,972,792	W/S 3A,3B,3C line 10	(1)
7		Loss On Reacquired Debt	(A)(1)(f)	4,198,950	1,574,739	273,655	6,047,344	W/S 3A,3B,3C line 11	(1)
8		Other Regulatory Assets	(A)(1)(g)	15,337,661	6,755,912	7,681,218	29,774,791	W/S 3A,3B,3C line 15	(2)
9		Net Investment (Line 4-5-6+7+8)		1,694,206,712	412,138,946	510,504,673	2,616,850,331		(2)
10		Prepayments	(A)(1)(h)	12,693,335	4,251,680	846,180	17,791,195	W/S 3A,3B,3C line 16	(1)
11		Materials & Supplies	(A)(1)(i)	30,614,229	8,092,403	2,598,082	41,304,714	W/S 3A,3B,3C line 17	(1)
12		Cash Working Capital	(A)(1)(j)	7,275,352	2,046,333	1,488,631	10,810,316	W/S 3A,3B,3C line 23	(2)
13		Total Investment Base Excluding CWIP (Line 9+10+11+12)		1,744,789,628	426,529,362	515,437,566	2,686,756,556		(2)
14		NEEWS Construction Work In Progress	(A)(1)(l)	164,948,530		-	164,948,530	(a)	(1)
15		Total Investment Base Including CWIP (Line 13+14)		1,909,738,158	426,529,362	515,437,566	2,851,705,086		(2)
	II.	REVENUE REQUIREMENTS							
16		Investment Return and Income Taxes	(A)	216,835,476	50,812,016	59,209,860	326,857,352	W/S 2A,2B,2C, line 15	(2)
17		Investment Return and Income Taxes-CWIP		20,499,144	-	-	20,499,144	W/S 2A,2B,2C, line 15	(1)
18		Depreciation Expense	(B)	57,857,303	12,315,183	13,853,324	84,025,810	W/S 4A,4B,4C line 3	(1)
19		Amortization of Loss on Reacquired Debt	(C)	460,401	195,905	41,048	697,354	W/S 4A,4B,4C line 4	(1)
20		Investment Tax Credit	(D)	(332,148)	(3,850)	(29,425)	(365,423)	W/S 4A,4B,4C line 5	(1)
21		Property Tax Expense	(E)	35,184,843	14,352,660	15,469,033	65,006,536	W/S 4A,4B,4C line 8	(1)
22		Payroll Tax Expense	(F)	250,119	(3,240)	15,117	261,996	W/S 4A,4B,4C line 18	(1)
23		Operation & Maintenance Expense	(G)	29,352,552	8,159,213	5,263,108	42,774,873	W/S 4A,4B,4C line 16	(1)
24		Administrative & General Expense	(H)	28,850,267	8,211,448	6,645,940	43,707,655	W/S 4A,4B,4C line 17	(2)
25		Transmission Related Integrated Facilities Charge	(I)	-	-	-	-	N/A	(1)
26		Transmission Related Expense from Generators	(L)	-	-	-	-	N/A	(1)
27		Transmission Related Taxes and Fees Charge	(M)	7,642,269	125,466	17,047	7,784,782	Attachment B line 16	(1)
28		Revenue for ST Trans. Service Under the OATT	(N)	(460,565)	(102,948)	(119,820)	(683,333)	Attachment C line 10	(1)
29		Total Revenue Requirements (Line 16 thru 28)		396,139,661	94,061,853	100,365,232	590,566,746		(2)

(a) Reflects actual information per Eversource's accounting records

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
Provided this support because these balances will be revised under the changed rates.

	CL&P	PSNH	WMECO
(3) Carrying Charge Factor (Line (16+ 18 thru 24) / Line 1)	15.25%	16.55%	14.00%

CL&P, PSNH and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Present Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Post-2003
Worksheet 1C

	(A)		(B)		(C)		(D)		(E)=(B)+(C)+(D)	(F)	(G)
Line	**I. INVESTMENT BASE**		**CL&P**		**PSNH**		**WMECO**		**TOTAL**	**Reference**	**Notes**
1	Transmission Plant	$	1,535,579,816	$	124,215,608	$	12,384,353	$	1,672,179,777	Attachment D, D2, D4	(1)
2	Accumulated Depreciation	$	213,218,089	$	18,074,549	$	1,442,093	$	232,734,731	Attachment D, D2, D4	(1)
3	Accumulated Deferred Income Taxes	$	155,340,565	$	15,930,789	$	2,675,475	$	173,946,829	Attachment D1, D3, D5	(1)
4	Net Investment (Line 1-2-3)	$	1,167,021,162	$	90,210,270	$	8,266,785	$	1,265,498,217		(1)
	II. INCREMENTAL RETURN										
5	Incremental Revenue Requirements	$	6,906,431	$	545,953	$	47,005	$	7,499,389	W/S 2A,2B,2C Post 2003	(1)

Note: ROE incentives approved in FERC Opinion No. 489. As a result of Opinion No. 531-B, these projects receive an ROE incentive of 67 bp.

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.

CL&P, PSNH and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Present Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
NEEWS
Worksheet 1E

Line	(A) I. INVESTMENT BASE	(B) CL&P	(C) WMECO	(D) = (B) + (C) Total	(E) Reference	(F) Notes
1	Transmission Plant	$ 200,288,632	$ 556,313,751	$ 756,602,383	Attachment F & F2	(1)
2	Accumulated Depreciation	$ 8,946,318	$ 22,283,705	$ 31,230,023	Attachment F & F2	(1)
3	Accumulated Deferred Income Taxes	$ 46,929,968	$ 142,742,742	$ 189,672,710	Attachment F1 & F3	(1)
4	Net Investment Excluding CWIP (Line 1-2-3)	$ 144,412,346	$ 391,287,304	$ 535,699,650		(1)
5	NEEWS Construction Work In Progress	$ 164,948,530	$ -	$ 164,948,530	Attachment F & F2	(1)
6	Net Investment Including CWIP (Line 4+5)	$ 309,360,876	$ 391,287,304	$ 700,648,180		(1)
	II. INCREMENTAL RETURN					
7	Incremental Revenue Requirements	$ 854,632	$ 2,224,860	$ 3,079,492	W/S 2A & 2C NEEWS	(1)
8	Incremental Revenue Requirements-CWIP	$ 976,165	$ -	$ 976,165	W/S 2A & 2C NEEWS	(1)
9	Total Incremental Revenue Requirements (line 7+8)	$ 1,830,797	$ 2,224,860	$ 4,055,657		(1)

Note: Incentives approved in FERC Docket No. ER08-1548. As a result of Opinion No. 531-B, this project receives ROE incentives of 67 bp.

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.

Connecticut Light & Power Company (CL&P)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Present Rates
Under Attachment F of the ISO-NE OATT
For Calendar Year 2014
Investment Return and Income Taxes - Pre 1997
Worksheet 2A

Line	(A)	(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 2,579,060,322	45.78%	5.36%	2.45%		
2	PREFERRED STOCK	$ 116,868,097	2.07%	4.80%	0.10%	0.10%	
3	COMMON EQUITY	$ 2,938,441,767	52.15%	11.07%	5.77%	5.77%	
4	TOTAL INVESTMENT RETURN	$ 5,634,370,186	100.00%		8.32%	5.87%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.0832

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit (W/S 1A) + Eq. AFUDC of Deprec. Exp. (Att. I)) / PTF Inv. Base (W/S 1A) x Federal Income Tax Rate)
(1 - Federal Income Tax Rate)

6 = 0.0587 +((49,341) + 269,748) / 259,191,875) x 0.35)
7 (1 - 0.35)

8 = 0.032066

(c) State Income Tax = R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate
(1 - State Income tax Rate)

9 = 0.0587 +((49,341) + 269,748) / 259,191,875) + 0.032066)* 0.09
10 (1 - 0.09)

11 = 0.009061

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.124327

Line		**Pre-1997 PTF**	
13	INVESTMENT BASE	$ 259,191,875	From Worksheet 1A, line 13
14	x Cost of Capital Rate	0.124327	
15	= Investment Return and Income Taxes	$ 32,224,548	To Worksheet 1A, line 14

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Provided this support because the balance in "Total Inv. Base" will be revised under the Changed Rates

Connecticut Light & Power Company (CL&P)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Present Rates
Under Attachment F of the ISO-NE OATT
For Calendar Year 2014
Investment Return and Income Taxes - Post 1996
Worksheet 2A

(A)		(B)	(C)	(D)	(E)	(F)	(G)
Line		CAPITALIZATION 12/31/2014 (Attachment H)	CAPITALIZATION RATIOS	COST OF CAPITAL	WEIGHTED COST OF CAPITAL	EQUITY PORTION	
1	LONG-TERM DEBT	$ 2,579,060,322	45.78%	5.36%	2.45%		
2	PREFERRED STOCK	$ 116,868,097	2.07%	4.80%	0.10%	0.10%	
3	COMMON EQUITY	$ 2,938,441,767	52.15%	11.07%	5.77%	5.77%	
4	TOTAL INVESTMENT RETURN	$ 5,634,370,186	100.00%		8.32%	5.87%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.0832

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit (W/S 1B) + Eq. AFUDC of Deprec. Exp. (Att. I)) / PTF Inv. Base (W/S 1B) x Federal Income Tax Rate)
(1 - Federal Income Tax Rate)

6 = 0.0587 +((332,148) + 1,815,862) / 1,909,738,158) x 0.35)
7 (1 - 0.35)

8 = 0.032026

(c) State Income Tax = R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate
(1 - State Income tax Rate)

9 = 0.0587 +((332,148) + 1,815,862) / 1,909,738,158) + 0.032026)* 0.09
10 (1 - 0.09)

11 = 0.009050

12 (a)+(b)+(c) Cost of Capital Rate = 0.124276

Line		Post - 1996 Total PTF	-	Post - 1996 PTF CWIP	=	Post -1996 PTF Excluding CWIP	
13	INVESTMENT BASE	$ 1,909,738,158		$ 164,948,530		$ 1,744,789,628	From Worksheet 1B, line 13, 14
14	x Cost of Capital Rate	0.124276		0.124276		0.124276	
15	= Investment Return and Income Taxes	$ 237,334,619		$ 20,499,144		$ 216,835,476	To Worksheet 1B, line 16

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Provided this support because the balance in "Total Inv. Base" will be revised under the Changed Rates

Connecticut Light & Power Company (CL&P)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Present Rates
Under Attachment F of the ISO-NE OATT
For Calendar Year 2014
Investment Return and Income Taxes - 50bp

Line	(A)	(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 2,579,060,322	45.78%		0.00%		
2	PREFERRED STOCK	$ 116,868,097	2.07%		0.00%	0.00%	
3	COMMON EQUITY	$ 2,938,441,767	52.15%	0.50%	0.26%	0.26%	
4	TOTAL INVESTMENT RETURN	$ 5,634,370,186	100.00%		0.26%	0.26%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.0026

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit (W/S 1B) + Eq. AFUDC of Deprec. Exp. (Att. I)) / PTF Inv. Base (W/S 1B) x Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

6 = 0.0026 +(0 + 0) / 2,168,930,033) x 0.35)
7 (1 - 0.35)

8 = 0.001400

(c) State Income Tax = R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate / (1 - State Income tax Rate)

9 = 0.0026 +(0 + 0) / 2,168,930,033) + 0.001400)* 0.09
10 (1 - 0.09)

11 = 0.000396

12 (a)+(b)+(c) Cost of Capital Rate = 0.004396

Line		Total PTF
13	INVESTMENT BASE	$ 2,168,930,033
14	x Cost of Capital Rate	0.004396
15	= Investment Return and Income Taxes	$ 9,534,616

Notes:
(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-224, Schedule 1, Pages 2, 3, 4 of 4, Line 14
(2) Provided this support because the balance in "Total Inv. Base" will be revised under the Changed Rates

Connecticut Light & Power Company (CL&P)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Present Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Worksheet 3A

					Pre-1997 PTF		Post-1996 PTF			
		(1)	(2)	(3)	(4)	(5) = (3)*(4)	(6)	(7) = (3)*(6)		
LN.		Transmission	Wage/Plant Allocation Factors (a)	Transmission	PTF Allocation Factor (b)	PTF Allocated	PTF Allocation Factor (b)	PTF Allocated	Reference	Notes
	Transmission Plant									
1	Transmission Plant					358,812,326		2,415,403,244	Attachment A (H1)	(1)
2	General Plant	104,400,554		104,400,554	11.5201%	12,027,048	77.5497%	80,962,316	FF1 page 204 ln. 99, footnote	(1)
3	Total (line 1+2)	104,400,554		104,400,554		370,839,374		2,496,365,560		(1)
										(1)
4	Transmission Plant Held for Future Use	730,526 (c)		730,526	11.5201%	84,157	77.5497%	566,521	(c)	(1)
	Transmission Accumulated Depreciation									
5	Transmission Accum. Depreciation	605,238,764		605,238,764	11.5201%	69,724,111	77.5497%	469,360,846	FF1 page 219 ln. 25	(1)
6	General Plant Accum. Depreciation	28,802,317		28,802,317	11.5201%	3,318,056	77.5497%	22,336,110	FF1 page 219 ln. 28, footnote	(1)
7	Total (line 5+6)	634,041,081		634,041,081		73,042,167		491,696,956	Schedule 2, Page 6,7,8	(1)
	Transmission Accumulated Deferred Taxes									
8	Accumulated Deferred Taxes (281 to 283)	(470,775,688)		(470,775,688)	11.5201%	(54,233,830)	77.5497%	(365,085,134)	FF1 page 274 ln. 9 & 276 ln. 19 fns	(1)
9	Accumulated Deferred Taxes (190)	44,513,531 (d)		44,513,531	11.5201%	5,128,003	77.5497%	34,520,110	(d)	(1)
10	Total (line 8+9)	(426,262,157)		(426,262,157)		(49,105,827)		(330,565,024)		(1)
11	Transmission loss on Reacquired Debt	5,414,528		5,414,528	11.5201%	623,759	77.5497%	4,198,950	FF1 page 110 ln. 81, footnote	(1)
	Other Regulatory Assets									
12	FAS 106	66,791		66,791	11.5201%	7,694	77.5497%	51,796	FF1 page 232 Ln. 27, footnote	(1)
13	FAS 109	23,019,567		23,019,567	11.5201%	2,651,877	77.5497%	17,851,605	FF1 page 232 ln. 7, footnote	(1)
14	Other Regulatory Liabilities (254.DK)	(3,308,510)		(3,308,510)	11.5201%	(381,144)	77.5497%	(2,565,740)	FF1 page 278 ln. 3, footnote	(1)
15	Total (line 12+13+14)	19,777,848		19,777,848		2,278,427		15,337,661		(2)
16	Transmission Prepayments (165)	16,368,000		16,368,000	11.5201%	1,885,610	77.5497%	12,693,335	FF1 page 110 ln. 57, footnote	(1)
17	Transmission Materials and Supplies	39,476,915		39,476,915	11.5201%	4,547,780	77.5497%	30,614,229	FF1 page 227 ln. 8	(1)
	Cash Working Capital									
18	Operation & Maintenance Expense					4,360,357		29,352,552	W/S 4A, Line 16	(1)
19	Administrative & General Expense					4,285,741		28,850,267	W/S 4A, Line 17	(2)
20	Transmission Support Expense					-		-	W/S 7	(1)
21	Subtotal (line 18+19+20)					8,646,098		58,202,819		(2)
22						0.125		0.125	x 45 / 360	(1)
23	Total (line 21 * line 22)					1,080,762		7,275,352		(2)

(a) All items are specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries and Plant Allocation Factors are not used (column 2

(b) W/S 5A & 5B

(c)	Account 105	32,127,498	FF1 page 214 ln. 33	(1)
	Less Third Underground Conduit Duct	31,396,972	FF1 page 214 ln. 22	(1)
		730,526		(1)
(d)	Account 190	46,955,376	FF1 page 234 ln. 18, footnote	(1)
	Less Reserve for Disputed Transactions	2,441,845	FF1 page 234 ln. 18, footnote	(1)
	Total Account 190	44,513,531		(1)

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
Provided this support because these balances will be revised under the changed rates.

Connecticut Light & Power Company (CL&P)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Present Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Worksheet 4A

					PRE-97 PTF		POST-96 PTF			
		(1)	(2)	(3)	(4)	(5) = (3)*(4)	(6)	(7) = (3)*(6)		
			Wage/Plant		PTF		PTF	Post-96		
			Allocation		Allocation	PTF	Allocation	PTF		
LN.		Transmission	Factors (a)	Transmission	Factor (b)	Allocated	Factor (b)	Allocated	Reference	Notes
	Depreciation Expense									
1	Transmission Depreciation	69,626,166		69,626,166	11.5201%	8,021,004	77.5497%	53,994,883	FF1 page 336 ln. 7	(1)
2	General Depreciation	4,980,574		4,980,574	11.5201%	573,767	77.5497%	3,862,420	FF1 page 336 ln. 10, footnote	(1)
3	Total (line 1+2)	74,606,740		74,606,740		8,594,771		57,857,303		(1)
4	Amortization of Loss on Reacquired Debt	593,685		593,685	11.5201%	68,393	77.5497%	460,401	FF1 page 114 ln. 64, footnote	(1)
5	Amortization of Investment Tax Credits	428,304		428,304	11.5201%	49,341	77.5497%	332,148	FF1 page 266 ln. 8(f), footnote	(1)
	Property Taxes									
6	Transmission Property Taxes	45,370,701		45,370,701	11.5201%	5,226,750	77.5497%	35,184,843	FF1 page 262 ln. 25i, footnote	(1)
7	General Property Taxes (c)	-		-	11.5201%	-	77.5497%	-		(1)
8	Total (line 6+7)	45,370,701		45,370,701		5,226,750		35,184,843		(1)
	Transmission Operation and Maintenance									
9	Operation and Maintenance	77,432,007		77,432,007	11.5201%	8,920,245	77.5497%	60,048,289	FF1 page 321 ln. 112	(1)
10	Transmission of Electricity by Others - #565	21,727,966		21,727,966	11.5201%	2,503,083	77.5497%	16,849,972	FF1 page 321 ln. 96	(1)
11	Account 561.1	3,245,594		3,245,594	11.5201%	373,896	77.5497%	2,516,948	FF1 page 321 ln. 85	(1)
12	Account 561.2	5,212,556		5,212,556	11.5201%	600,492	77.5497%	4,042,322	FF1 page 321 ln. 86	(1)
13	Account 561.3	2,238,612		2,238,612	11.5201%	257,890	77.5497%	1,736,037	FF1 page 321 ln. 87	(1)
14	Account 561.4	7,157,291		7,157,291	11.5201%	824,527	77.5497%	5,550,458	FF1 page 321 ln. 88	(1)
15	**Station Expenses & Rents	-		-	11.5201%	-	77.5497%	-	FF1 page 321 ln. 93 + ln. 98	(1)
16	O&M less lines 10 thru 15	37,849,988		37,849,988		4,360,357		29,352,552		(1)
	Transmission Administrative and General									
17	Administrative and General	37,202,294		37,202,294	11.5201%	4,285,741	77.5497%	28,850,267	FF1 page 320 ln. 197 b, footnote	(2)
18	*Payroll Tax Expense*	322,527		322,527	11.5201%	37,155	77.5497%	250,119		(1)
	Federal Unemployment	5,226							FF1 page 262 ln. 3i, footnote	(1)
	FICA	233,351							FF1 page 262 ln. 5i, footnote	(1)
	Medicare	65,613							FF1 page 262 ln. 9i, footnote	(1)
	CT Unemployment	16,786							FF1 page 262 ln. 15i, footnote	(1)
	DC Unemployment	11							FF1 page 262.1 ln. 14i, footnote	(1)
	FL Unemployment	1							FF1 page 262.1 ln. 18i, footnote	(1)
	GA Unemployment	-							FF1 page 262 footnote	(1)
	MA Unemployment	(285)							FF1 page 262 ln. 32i, footnote	(1)
	MA Universal Health	64							FF1 page 262 ln. 33i, footnote	(1)
	MI Unemployment	6							FF1 page 262.1 ln. 22i, footnote	(1)
	NH Unemployment	1,754							FF1 page 262.1 ln. 4i, footnote	(1)
	NJ Unemployment	-							FF1 page 262 footnote	(1)
	NY Unemployment	-							FF1 page 262.1 ln. 10i, footnote	(1)
	Total	322,527	To Line 18							(1)

** To the extent that PTF Support Payments are reflected in worksheet 7 they will be excluded from this calculation.
(a) All items are specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries and Plant Allocation Factors are not used (column 2).
(b) W/S 5A & 5B
(c) Transmission related general property taxes are included in the Transmission Property tax number footnoted in the FF1.

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
Provided this support because these balances will be revised under the changed rates.

Public Service Company of New Hampshire (PSNH)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Present Rates
Under Attachment F of the ISO-NE OATT
For Calendar Year 2014
Investment Return and Income Taxes - Pre 1997
Worksheet 2B

Line	(A)	(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 1,070,020,120	46.56%	4.15%	1.93%		
2	PREFERRED STOCK	$ -	0.00%	0.00%	0.00%	0.00%	
3	COMMON EQUITY	$ 1,228,095,985	53.44%	11.07%	5.92%	5.92%	
4	TOTAL INVESTMENT RETURN	$ 2,298,116,105	100.00%		7.85%	5.92%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.0785

(b) Federal Income Tax =((R.O.E. + (PTF Inv. (Tax Credit (W/S 1A) + Eq. AFUDC of Deprec. Exp. (Att. I)) / PTF Inv. Base (W/S 1A) x Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

6 =(0.0592 +((600) + 29,005) / 66,535,116) x 0.35)
7 (1 - 0.35)

8 = 0.032107

(c) State Income Tax =(R.O.E. + +(PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate / (1 - State Income Tax Rate)

9 =(0.0592 +((600) + 29,005) / 66,535,116) + 0.032107)* 0.085
10 (1 - 0.085)

11 = 0.008522

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.119129

Line		**Pre-1997 PTF**	
13	INVESTMENT BASE	$ 66,535,116	From Worksheet 1A, line 13
14	x Cost of Capital Rate	0.1191290	
15	= Investment Return and Income Taxes	$ 7,926,262	To Worksheet 1A, line 14

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Provided this support because the balance in "Total Inv. Base" will be revised under the Changed Rates

Public Service Company of New Hampshire (PSNH)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Present Rates
Under Attachment F of the ISO-NE OATT
For Calendar Year 2014
Investment Return and Income Taxes - Post 1996
Worksheet 2B

Line	(A)	(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 1,070,020,120	46.56%	4.15%	1.93%		
2	PREFERRED STOCK	$ -	0.00%	0.00%	0.00%	0.00%	
3	COMMON EQUITY	$ 1,228,095,985	53.44%	11.07%	5.92%	5.92%	
4	TOTAL INVESTMENT RETURN	$ 2,298,116,105	100.00%		7.85%	5.92%	

Cost of Capital Rate=

Line											
5	(a) Weighted Cost of Capital	=	0.0785								
	(b) Federal Income Tax	= (	(R.O.E. +	(PTF Inv. (Tax Credit (W/S 1B) +	Eq. AFUDC of Deprec. Exp. (Att. I)	) /	PTF Inv. Base (W/S 1A)	x	Federal Income Tax Rate)		
					(1 - Federal Income Tax Rate)						
6		= (	0.0592	+((3,850) +	186,109	) /	426,529,362)	x	0.35)		
7					(1	-	0.35)				
8		=	0.032107								
	(c) State Income Tax	= (	R.O.E. +	+(PTF Inv. (Tax Credit +	Eq. AFUDC of Deprec. Exp.	) /	PTF Inv. Base)	+	Federal Income Tax)*State Income Tax Rate		
					(1 - State Income Tax Rate)						
9		= (	0.0592	+((3,850) +	186,109	) /	426,529,362)	+	0.032107)*		0.085
10					(1	-	0.085)				
11		=	0.008522								
12	(a)+(b)+(c) Cost of Capital Rate	=	0.119129								

Line		Post - 1996Total PTF	
13	INVESTMENT BASE	$ 426,529,362	From Worksheet 1A, line 13
14	x Cost of Capital Rate	0.119129	
15	= Investment Return and Income Taxes	$ 50,812,016	To Worksheet 1B, line 16

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Provided this support because the balance in "Total Inv. Base" will be revised under the Changed Rates

Public Service Company of New Hampshire (PSNH)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Present Rates
Under Attachment F of the ISO-NE OATT
For Calendar Year 2014
Investment Return and Income Taxes - 50bp

Line	(A)	(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 1,070,020,120	46.56%		0.00%		
2	PREFERRED STOCK	$ -	0.00%		0.00%	0.00%	
3	COMMON EQUITY	$ 1,228,095,985	53.44%	0.50%	0.27%	0.27%	
4	TOTAL INVESTMENT RETURN	$ 2,298,116,105	100.00%		0.27%	0.27%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.0027

(b) Federal Income Tax = ((R.O.E. + (PTF Inv. (Tax Credit (W/S 1B) + Eq. AFUDC of Deprec. Exp. (Att. I)) / PTF Inv. Base (W/S 1A) x Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

6 = (0.0027 +(0 + 0) / 493,064,478) x 0.35)
7 (1 - 0.35)

8 = 0.001454

(c) State Income Tax = (R.O.E. + +(PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate / (1 - State Income Tax Rate)

9 = (0.0027 +(0 + 0) / 493,064,478) + 0.001454)* 0.085
10 (1 - 0.085)

11 = 0.000386

12 (a)+(b)+(c) Cost of Capital Rate = 0.004540

Line		Total PTF
13	INVESTMENT BASE	$ 493,064,478
14	x Cost of Capital Rate	0.004540
15	= Investment Return and Income Taxes	$ 2,238,513

Notes:

(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-224, Schedule 1, Pages 2, 3, 4 of 4, Line 14
(2) Provided this support because the balance in "Total Inv. Base" will be revised under the Changed Rates

Public Service Company of New Hampshire (PSNH)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Present Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Worksheet 3B

LN.		(1) Transmission	(2) Wage/Plant Allocation Factors (a)	(3) Transmission	Pre-1997 PTF (4) PTF Allocation Factor (b)	Pre-1997 PTF (5) = (3)*(4) PTF Allocated	Post-1996 PTF (6) PTF Allocation Factor (b)	Post-1996 PTF (7) = (3)*(6) Post-96 PTF Allocated	Reference	Notes
	Transmission Plant									
1	Transmission Plant					88,564,672		568,289,707	Attachment A1	(1)
2	General Plant	59,322,426		59,322,426	12.3666%	7,336,167	79.3521%	47,073,591	FF1 page 204 ln. 99, footnote	(1)
3	Total (line 1+2)	59,322,426		59,322,426		95,900,839		615,363,298		(1)
										(1)
4	Transmission Plant Held for Future Use	9,205,247		9,205,247	12.3666%	1,138,376	79.3521%	7,304,557	FF1 page 214 ln. 35	(1)
	Transmission Accumulated Depreciation									
5	Transmission Accum. Depreciation	123,132,357		123,132,357	12.3666%	15,227,286	79.3521%	97,708,111	FF1 page 219 ln. 25	(1)
6	General Plant Accum. Depreciation	16,139,432		16,139,432	12.3666%	1,995,899	79.3521%	12,806,978	FF1 page 219 ln. 28, footnote	(1)
7	Total (line 5+6)	139,271,789		139,271,789		17,223,185		110,515,089		(1)
	Transmission Accumulated Deferred Taxes									
8	Accumulated Deferred Taxes (281-283)	(145,475,861)		(145,475,861)	12.3666%	(17,990,418)	79.3521%	(115,438,151)	FF1 page 274 ln. 9 & 276 ln. 19 fns	(1)
9	Accumulated Deferred Taxes (190)	8,939,499 (c)		8,939,499	12.3666%	1,105,512	79.3521%	7,093,680	(c)	(1)
10	Total (line 8+9)	(136,536,362)		(136,536,362)		(16,884,906)				
				-						
11	Transmission loss on Reacquired Debt	1,984,496		1,984,496	12.3666%	245,415	79.3521%	1,574,739	FF1 page 110 ln. 81, footnote	(1)
	Other Regulatory Assets									
12	FAS 106	350,591		350,591	12.3666%	43,356	79.3521%	278,201	FF1 page 232.1 ln. 15, footnote	(1)
13	FAS 109	8,171,016		8,171,016	12.3666%	1,010,477	79.3521%	6,483,873	FF1 page 232 ln. 1, footnote	(1)
14	Other Regulatory Liabilities (254.DK)	(7,765)		(7,765)	12.3666%	(960)	79.3521%	(6,162)	FF1 page 278 ln. 1, footnote	(1)
15	Total (line 12+13+14)	8,513,842		8,513,842		1,052,873		6,755,912		(2)
16	Transmission Prepayments	5,357,993		5,357,993	12.3666%	662,602	79.3521%	4,251,680	FF1 page 110 ln. 57, footnote	(1)
17	Transmission Materials and Supplies	10,198,096		10,198,096	12.3666%	1,261,158	79.3521%	8,092,403	FF1 page 227 ln. 8	(1)
	Cash Working Capital									
18	Operation & Maintenance Expense					1,271,570		8,159,213	W/S 4B, Line 16	(1)
19	Administrative & General Expense					1,279,710		8,211,448	W/S 4B, Line 17	(2)
20	Transmission Support Expense					504,271		-	W/S 7	(1)
21	Subtotal (line 18+19+20)					3,055,551		16,370,661		(2)
22						0.125		0.125	x 45 / 360	(1)
23	Total (line 21 * line 22)					381,944		2,046,333		(2)

(a) All items are specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries and Plant Allocation Factors are not used (column 2).
(b) W/S 5A & 5B
(c)

Account 190	8,939,499	FF1 page 234 ln. 18, footnote	(1)
Less Reserve for Disputed Transactions	-	FF1 page 234 ln. 18, footnote	(1)
Total Account 190	8,939,499		(1)

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
Provided this support because these balances will be revised under the changed rates.

Public Service Company of New Hampshire (PSNH)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Present Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Worksheet 4B

LN.		(1) Transmission	(2) Wage/Plant Allocation Factors (a)	(3) Transmission	Pre-1997 PTF (4) PTF Allocation Factor (b)	Pre-1997 PTF (5) = (3)*(4) PTF Allocated	Post-1996 PTF (6) PTF Allocation Factor (b)	Post-1996 PTF (7) = (3)*(6) Post-96 PTF Allocated	Reference	Notes
	Depreciation Expense									
1	Transmission Depreciation	12,792,512		12,792,512	12.3666%	1,581,999	79.3521%	10,151,127	FF 1 page 336 ln. 7	(1)
2	General Depreciation	2,727,156		2,727,156	12.3666%	337,256	79.3521%	2,164,056	FF1 page 336 ln. 10, footnote	(1)
3	Total (line 1+2)	15,519,668		15,519,668		1,919,255		12,315,183		(1)
4	Amortization of Loss on Reacquired Debt	246,881		246,881	12.3666%	30,531	79.3521%	195,905	FF1 page 114 ln. 64, footnote	(1)
5	Amortization of Investment Tax Credits	4,852		4,852	12.3666%	600	79.3521%	3,850	FF1 page 266 ln. 8(f), footnote	(1)
	Property Taxes									
6	Transmission Property Taxes	18,087,310		18,087,310	12.3666%	2,236,785	79.3521%	14,352,660	FF1 page 262 ln. 23i + ln. 30i +	(1)
7	General Property Taxes (c)	-		-	12.3666%	-	79.3521%	-	page 262.1 ln. 2i, footnote	(1)
8	Total (line 6+7)	18,087,310		18,087,310		2,236,785		14,352,660		(1)
	Transmission Operation and Maintenance									
9	Operation and Maintenance	51,082,852		51,082,852	12.3666%	6,317,212	79.3521%	40,535,316	FF1 page 321 ln. 112	(1)
10	Transmission of Electricity by Others - #5	37,174,569		37,174,569	12.3666%	4,597,230	79.3521%	29,498,801	FF1 page 321 ln. 96	(1)
11	Account 561.1	653,575		653,575	12.3666%	80,825	79.3521%	518,625	FF1 page 321 ln. 85	(1)
12	Account 561.2	474,690		474,690	12.3666%	58,703	79.3521%	376,676	FF1 page 321 ln. 86	(1)
13	Account 561.3	36,962		36,962	12.3666%	4,571	79.3521%	29,330	FF1 page 321 ln. 87	(1)
14	Account 561.4	2,460,768		2,460,768	12.3666%	304,313	79.3521%	1,952,671	FF1 page 321 ln. 88	(1)
15	**Station Expenses & Rents	-		-	12.3666%	-	79.3521%	-	FF1 page 321 ln. 93 + ln. 98	(1)
16	O&M less lines 10 thru 15	10,282,288		10,282,288		1,271,570		8,159,213		(1)
	Transmission Administrative and General									
17	Administrative and General	10,348,117		10,348,117	12.3666%	1,279,710	79.3521%	8,211,448	FF1 page 320 ln. 197 b, footnote	(2)
18	*Payroll Tax Expense*	(4,083)		(4,083)	12.3666%	(505)	79.3521%	(3,240)		(1)
	Federal Unemployment	(51)							FF1 page 262 ln. 2i, footnote	(1)
	FICA	(3,062)							FF1 page 262 ln. 4i, footnote	(1)
	Medicare	(816)							FF1 page 262 ln. 7i, footnote	(1)
	CT Unemployment	(128)							FF1 page 262.1 ln. 7i, footnote	(1)
	DC Unemployment	0							FF1 page 262 ln. 26i, footnote	(1)
	FL Unemployment	0							FF1 page 262.1 ln. 27i, footnote	(1)
	GA Unemployment	0							FF1 page 262.1, footnote	(1)
	MA Unemployment	2							FF1 page 262.1 ln. 15i, footnote	(1)
	MA Universal Health	(1)							FF1 page 262.1 ln. 16i, footnote	(1)
	MI Unemployment	0							FF1 page 262.1 ln. 31i, footnote	(1)
	NH Unemployment	(27)							FF1 page 262 ln. 14i, footnote	(1)
	NJ Unemployment	0							FF1 page 262, footnote	(1)
	NY Unemployment	0							FF1 page 262 footnote	(1)
	Total	(4,083)	To Line 19							(1)

** To the extent that PTF Support Payments are reflected in worksheet 7 they will be excluded from this calculation.
(a) All items are specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries and Plant Allocation Factors are not used (column 2).
(b) W/S 5A & 5B
(c) Transmission related general property taxes are included in the Transmission Property tax number footnoted in the FF1.

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
Provided this support because these balances will be revised under the changed rates.

Western Massachusetts Electric Company (WMECO)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Present Rates
Under Attachment F of the ISO-NE OATT
For Calendar Year 2014
Investment Return and Income Taxes - Pre 1997
Worksheet 2C

Line	(A)	(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 567,833,428	49.55%	4.31%	2.14%		
2	PREFERRED STOCK	$ -	0.00%	0.00%	0.00%	0.00%	
3	COMMON EQUITY	$ 578,162,814	50.45%	11.07%	5.58%	5.58%	
4	TOTAL INVESTMENT RETURN	$ 1,145,996,242	100.00%		7.72%	5.58%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.0772

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit (W/S 1A) + Eq. AFUDC of Deprec. Exp. (Att. I)) / PTF Inv. Base (W/S 1A) x Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

6 = (0.0558 +((2,179) + 11,396) / 38,220,315) x 0.35)
7 (1 - 0.35)

8 = 0.030176

(c) State Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate / (1 - State Income Tax Rate)

9 = (0.0558 +((2,179) + 11,396) / 38,220,315) + 0.030176)* 0.08
10 (1 - 0.08)

11 = 0.007497

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.114873

Line		Pre-1997 PTF	
13	INVESTMENT BASE	$ 38,220,315	From Worksheet 1A, line 13
14	x Cost of Capital Rate	0.114873	
15	= Investment Return and Income Taxes	$ 4,390,482	To Worksheet 1A, line 14

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Provided this support because the balance in "Total Inv. Base" will be revised under the Changed Rates

Western Massachusetts Electric Company (WMECO)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Present Rates
Under Attachment F of the ISO-NE OATT
For Calendar Year 2014

Investment Return and Income Taxes - Post-1996

Worksheet 2C

Line	(A)	(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 567,833,428	49.55%	4.31%	2.14%		
2	PREFERRED STOCK	$ -	0.00%	0.00%	0.00%	0.00%	
3	COMMON EQUITY	$ 578,162,814	50.45%	11.07%	5.58%	5.58%	
4	TOTAL INVESTMENT RETURN	$ 1,145,996,242	100.00%		7.72%	5.58%	

Cost of Capital Rate=

Line			
5	(a) Weighted Cost of Capital	=	0.0772
	(b) Federal Income Tax	=	(R.O.E. + (PTF Inv. (Tax Credit (W/S 1B) + Eq. AFUDC of Deprec. Exp. (Att. I)) / PTF Inv. Base (W/S 1B) x Federal Income Tax Rate) / (1 - Federal Income Tax Rate)
6		=	(0.0558 +((29,425) + 153,859) / 515,437,566) x 0.35)
7			(1 - 0.35)
8		=	0.030176
	(c) State Income Tax	=	(R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate / (1 - State Income Tax Rate)
9		=	(0.0558 +((29,425) + 153,859) / 515,437,566) + 0.030176)* 0.08
10			(1 - 0.08)
11		=	0.007497
12	(a)+(b)+(c) **Cost of Capital Rate**	=	0.114873

Line		**Post - 1996 Total PTF**	-	**Post - 1996 PTF CWIP**	=	**Post -1996 PTF Excluding CWIP**	
13	INVESTMENT BASE	$ 515,437,566		$ -		$ 515,437,566	From Worksheet 1B, line 13, 14
14	x Cost of Capital Rate	0.1148730		0.1148730		0.1148730	
15	= Investment Return and Income Taxes	$ 59,209,860		$ -		$ 59,209,860	To Worksheet 1A, line 14

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Provided this support because the balance in "Total Inv. Base" will be revised under the Changed Rates

Western Massachusetts Electric Company (WMECO)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Present Rates
Under Attachment F of the ISO-NE OATT
For Calendar Year 2014

Investment Return and Income Taxes - 50bp

	(A)	(B)	(C)	(D)	(E)	(F)	(G)
Line		CAPITALIZATION (B) (Attachment H)	CAPITALIZATION RATIOS	COST OF CAPITAL	WEIGHTED COST OF CAPITAL	EQUITY PORTION	
1	LONG-TERM DEBT	$ 578,162,814	50.45%		0.00%		
2	PREFERRED STOCK		0.00%		0.00%	0.00%	
3	COMMON EQUITY	$ 578,162,814	50.45%	0.50%	0.25%	0.25%	
4	TOTAL INVESTMENT RETURN	$ 1,156,325,628	100.90%		0.25%	0.25%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.0025

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit (W/S 1B) + Eq. AFUDC of Deprec. Exp. (Att. I)) / PTF Inv. Base (W/S 1B) x Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

6 = (0.0025 +(0 + 0) / 553,657,881) x 0.35)
7 (1 - 0.35)

8 = 0.001346

(c) State Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate / (1 - State Income Tax Rate)

9 = (0.0025 +(0 + 0) / 553,657,881) + 0.001346)* 0.08
10 (1 - 0.08)

11 = 0.000334

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.004180

		Total PTF
13	INVESTMENT BASE	$ 553,657,881
14	x Cost of Capital Rate	0.0041800
15	= Investment Return and Income Taxes	$ 2,314,290

Notes:
(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-224, Schedule 1, Pages 2, 3, 4 of 4, Line 14
(2) Provided this support because the balance in "Total Inv. Base" will be revised under the Changed Rates

Western Massachusetts Electric Company (WMECO)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Present Rates
Under Attachment F of the ISO-NE OATT
For Calendar Year 2014
Worksheet 3C

LN.		(1) Transmission	(2) Wage/Plant Allocation Factors (a)	(3) Transmission	Pre-1997 PTF (4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	Post-1996 PTF (6) PTF Allocation Factor (b)	(7) = (3)*(6) Post-96 PTF Allocated	Reference	Notes
	Transmission Plant									
1	Transmission Plant					53,145,202		717,553,491	Attachment A2	(1)
2	General Plant	18,793,854		18,793,854	6.1211%	1,150,391	82.6455%	15,532,275	FF1 page 204 ln. 99, footnote	(1)
3	Total (line 1+2)	18,793,854		18,793,854		54,295,593		733,085,766		(1)
										(1)
4	Transmission Plant Held for Future Use	0		0	6.1211%	0	82.6455%	0	FF1 page 214 ln. 13	(1)
	Transmission Accumulated Depreciation									
5	Transmission Accum. Depreciation	54,279,720		54,279,720	6.1211%	3,322,516	82.6455%	44,859,746	FF1 page 219 ln. 25	(1)
6	General Plant Accum. Depreciation	4,371,591		4,371,591	6.1211%	267,589	82.6455%	3,612,923	FF1 page 219 ln. 28, footnote	(1)
7	Total (line 5+6)	58,651,311		58,651,311		3,590,105		48,472,669		(1)
	Transmission Accumulated Deferred Taxes									
8	Accumulated Deferred Taxes (281-283)	(225,957,746)		(225,957,746)	6.1211%	(13,831,100)	82.6455%	(186,743,909)	FF1 page 274 ln. 9 & 276 ln. 19, footnotes	(1)
9	Accumulated Deferred Taxes (190)	5,663,481 (c)		5,663,481	6.1211%	346,667	82.6455%	4,680,612	(c)	(1)
10	Total (line 8+9)	(220,294,265)		(220,294,265)		(13,484,433)		(182,063,297)		(1)
11	Transmission loss on Reacquired Debt	331,119		331,119	6.1211%	20,268	82.6455%	273,655	FF1 page 110 ln. 81, footnote	(1)
	Other Regulatory Assets									
12	FAS 106	22,693		22,693	6.1211%	1,389	82.6455%	18,755	FF1 page 232.1 ln. 1, footnote	(1)
13	FAS 109	9,336,822		9,336,822	6.1211%	571,516	82.6455%	7,716,463	FF1 page 232 ln. 9, footnote	(1)
14	Other Regulatory Liabilities (254.DK)	(65,339)		(65,339)	6.1211%	(3,999)	82.6455%	(54,000)	FF1 page 278 ln. 5, footnote	(1)
15	Total (line 12+13+14)	9,294,176		9,294,176		568,906		7,681,218		(2)
16	Transmission Prepayments	1,023,867		1,023,867	6.1211%	62,672	82.6455%	846,180	FF1 page 110 ln. 57, footnote	(1)
17	Transmission Materials and Supplies	3,143,646		3,143,646	6.1211%	192,426	82.6455%	2,598,082	FF1 page 227 ln. 8	(1)
	Cash Working Capital									
18	Operation & Maintenance Expense					389,810		5,263,108	W/S 4C, Line 16	(1)
19	Administrative & General Expense					492,228		6,645,940	W/S 4C, Line 17	(2)
20	Transmission Support Expense					357,869			W/S 7	(1)
21	Subtotal (line 19+20+21)					1,239,907		11,909,048		(2)
22						0.125		0.125	x 45 / 360	(1)
23	Total (line 22 * line 23)					154,988		1,488,631		(2)

(a) All items are specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries and Plant Allocation Factors are not used (column 2).
(b) W/S 5A & 5B

(c)			
Account 190	5,663,481	FF1 page 234 ln. 18, footnote	(1)
Less Reserve for Disputed Transactions	-	FF1 page 234 ln. 18, footnote	(1)
Total Account 190	5,663,481		(1)

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
Provided this support because these balances will be revised under the changed rates.

Western Massachusetts Electric Company (WMECO)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Present Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Worksheet 4C

					Pre-1997 PTF		Post-1996 PTF			
LN.		(1) Transmission	(2) Wage/Plant Allocation Factors (a)	(3) Transmission	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	(6) PTF Allocation Factor (b)	(7) = (3)*(6) Post-96 PTF Allocated	Reference	Notes
	Depreciation Expense									
1	Transmission Depreciation	15,972,687		15,972,687	6.1211%	977,704	82.6455%	13,200,707	FF1 page 336 ln. 7	(1)
2	General Depreciation	789,658		789,658	6.1211%	48,336	82.6455%	652,617	FF1 page 336 ln. 10, footnote	(1)
3	Total (line 1+2)	16,762,345		16,762,345		1,026,040		13,853,324		(1)
4	Amortization of Loss on Reacquired Debt	49,668		49,668	6.1211%	3,040	82.6455%	41,048	FF1 page 114, ln. 64, footnote	(1)
5	Amortization of Investment Tax Credits	35,604		35,604	6.1211%	2,179	82.6455%	29,425	FF1 page 266 ln. 8(f), footnote	(1)
	Property Taxes									
6	Transmission Property Taxes	18,717,332		18,717,332	6.1211%	1,145,707	82.6455%	15,469,033	FF1 page 262 ln. 32i, footnote	(1)
7	General Property Taxes (c)				6.1211%	-	82.6455%	-		(1)
8	Total (line 6+7)	18,717,332		18,717,332		1,145,707		15,469,033		(1)
	Transmission Operation and Maintenance									
9	Operation and Maintenance	20,725,279		20,725,279	6.1211%	1,268,615	82.6455%	17,128,510	FF1 page 321 ln. 112	(1)
10	Transmission of Electricity by Others - #565	13,174,678		13,174,678	6.1211%	806,435	82.6455%	10,888,279	FF1 page 321 ln. 96	(1)
11	Account 561.1	12,368		12,368	6.1211%	757	82.6455%	10,222	FF1 page 321 ln. 85	(1)
12	Account 561.2	50,569		50,569	6.1211%	3,095	82.6455%	41,793	FF1 page 321 ln. 86	(1)
13	Account 561.3	13,262		13,262	6.1211%	812	82.6455%	10,960	FF1 page 321 ln. 87	(1)
14	Account 561.4	1,106,108		1,106,108	6.1211%	67,706	82.6455%	914,148	FF1 page 321 ln. 88	(1)
15	**Station Expenses & Rents	-			6.1211%	-	82.6455%	-	FF1 page 321 ln. 93 + ln. 98	(1)
16	O&M less lines 10 thru 15	6,368,294		6,368,294		389,810		5,263,108		(1)
	Transmission Administrative and General									
17	Administrative and General	8,041,502		8,041,502	6.1211%	492,228	82.6455%	6,645,940	FF1 page 320 ln. 197, footnote	(2)
18	*Payroll Tax Expense*	18,291		18,291	6.1211%	1,120	82.6455%	15,117		(1)
	Federal Unemployment	283							FF1 page 262 ln. 3i, footnote	(1)
	FICA	13,202							FF1 page 262 ln. 5i, footnote	(1)
	Medicare	3,757							FF1 page 262 ln. 9i, footnote	(1)
	CT Unemployment	852							FF1 page 262 ln. 13i, footnote	(1)
	DC Unemployment	1							FF1 page 262.1 ln. 6i, footnote	(1)
	FL Unemployment	-							FF1 page 262.1 ln. 10i, footnote	(1)
	GA Unemployment	-							FF1 page 262.1 ln. 14i footnote	(1)
	MA Unemployment	69							FF1 page 262 ln. 22i, footnote	(1)
	MA Universal Health	19							FF1 page 262 ln. 27i, footnote	(1)
	MI Unemployment	-							FF1 page 262.1 ln. 14i footnote	(1)
	NH Unemployment	108							FF1 page 262 ln. 37i, footnote	(1)
	NJ Unemployment	-							FF1 page 262 footnote	(1)
	NY Unemployment	-							FF1 page 262.1, footnote	(1)
	Total	18,291	To Line 19							(1)

** To the extent that PTF Support Payments are reflected in worksheet 7 they will be excluded from this calculation.
(a) All items are specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries and Plant Allocation Factors are not used (column 2).
(b) W/S 5A & 5B
(c) Transmission related general property taxes are included in the Transmission Property tax number footnoted in the FF1.

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
Provided this support because these balances will be revised under the changed rates.

Exhibit No. ES-221
Schedule 3

CL&P's, PSNH's and WMECO's PTF Revenue Requirements under the Changed Rates for 2016

Eversource Energy Service Company

CL&P, PSNH and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For the Calendar Year 2016

Line	(A) Description	(B) Reference	(C) CL&P		(D) PSNH		(E) WMECO		(F)=(C)+(D)+(E) Total
1	2014 Actual PTF Revenue Requirements		$ 462,205,214	(1)	$ 109,658,517	(2)	$ 112,176,992	(3)	$ 684,040,723
2	Estimated 2015 PTF Plant Additions	(4)	$ 276,000,000		$ 114,000,000		$ 87,000,000		$ 477,000,000
3	Carrying Charge Factor (CCF)	Exhibit No. ES-221, Schedule 2, Page 3 of 20, Note (3)	15.25%		16.55%		14.00%		
4	2015 Incremental Estimated PTF Revenue Requirements	Line 2 x 3	42,090,000		18,867,000		12,180,000		$ 73,137,000
5	2015 Incremental Estimated PTF CWIP Rev. Req.	(4)	$ (19,400,000)		$ -		$ -		$ (19,400,000)
6	Total Estimated PTF Revenue Requirement for 2015	Line 1 + 4 + 5	$ 484,895,214		$ 128,525,517		$ 124,356,992		$ 737,777,723
7	Estimated 2016 PTF Plant Additions	(4)	$ 68,000,000		$ 117,000,000		$ 88,000,000		$ 273,000,000
8	Carrying Charge Factor (CCF)	Line 3	15.25%		16.55%		14.00%		
9	2016 Incremental Estimated PTF Revenue Requirements	Line 7 x 8	10,370,000		19,363,500		12,320,000		$ 42,053,500
10	Total Estimated PTF Revenue Requirement for 2016	Line 6 + 9	$ 495,265,214		$ 147,889,017		$ 136,676,992		$ 779,831,223

Notes:
(1) Exhibit No. ES-221: Schedule 3, Page 2 of 20, LN. 29(B) + Schedule 3, Page 3 of 20, LN. 29(B) + Schedule 3, Page 4 of 20, LN. 5(B) + Schedule 3, Page 5 of 20, LN. 9(B)
(2) Exhibit No. ES-221: Schedule 3, Page 2 of 20, LN. 29(C) + Schedule 3, Page 3 of 20, LN. 29(C) + Schedule 3, Page 4 of 20, LN. 5(C)
(3) Exhibit No. ES-221: Schedule 3, Page 2 of 20, LN. 29(D) + Schedule 3, Page 3 of 20, LN. 29(D) + Schedule 3, Page 4 of 20, LN. 5(D) + Schedule 3, Page 5 of 20, LN. 9(C)
(4) Based on Eversource's Forecast

CL&P, PSNH and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Pre-1997
Worksheet 1A

		(A)		(B)	(C)	(D)	(E)=(B)+(C)+(D)	(F)	(G)
LN.	I.	INVESTMENT BASE	Attachment F Reference Section:	CL&P	PSNH	WMECO	Total	Reference	Notes
1		Transmission Plant	(A)(1)(a)	358,812,326	88,564,672	53,145,202	500,522,200	W/S 3A,3B,3C line 1	(1)
2		General Plant	(A)(1)(b)	12,027,048	7,336,167	1,150,391	20,513,606	W/S 3A,3B,3C line 2	(1)
3		Plant Held For Future Use	(A)(1)(c)	84,157	1,138,376	0	1,222,533	W/S 3A,3B,3C line 4	(1)
4		Total Plant (Lines 1+2+3)		370,923,531	97,039,215	54,295,593	522,258,339		(1)
5		Accumulated Depreciation	(A)(1)(d)	73,042,167	17,223,185	3,590,105	93,855,457	W/S 3A,3B,3C line 7	(1)
6		Accumulated Deferred Income Taxes	(A)(1)(e)	49,105,827	16,884,906	13,484,433	79,475,166	W/S 3A,3B,3C line 10	(1)
7		Loss On Reacquired Debt	(A)(1)(f)	623,759	245,415	20,268	889,442	W/S 3A,3B,3C line 11	(1)
8		Other Regulatory Assets	(A)(1)(g)	3,926,568	1,419,326	806,798	6,152,692	W/S 3A,3B,3C line 16	(2)
9		Net Investment (Line 4-5-6+7+8)		253,325,864	64,595,865	38,048,121	355,969,850		(2)
10		Prepayments	(A)(1)(h)	1,885,610	662,602	62,672	2,610,884	W/S 3A,3B,3C line 17	(1)
11		Materials & Supplies	(A)(1)(i)	4,547,780	1,261,158	192,426	6,001,364	W/S 3A,3B,3C line 18	(1)
12		Cash Working Capital	(A)(1)(j)	1,183,771	404,847	169,857	1,758,475	W/S 3A,3B,3C line 24	(2)
13		Total Investment Base (Line 9+10+11+12)		260,943,025	66,924,472	38,473,076	366,340,573		(2)
	II.	REVENUE REQUIREMENTS							
14		Investment Return and Income Taxes	(A)	32,441,220	7,972,445	4,419,479	44,833,144	W/S 2A,2B,2C, line 15	(2)
15		Depreciation Expense	(B)	8,594,771	1,919,255	1,026,040	11,540,066	W/S 4A,4B,4C line 3	(1)
16		Amortization of Loss on Reacquired Debt	(C)	68,393	30,531	3,040	101,964	W/S 4A,4B,4C line 4	(1)
17		Investment Tax Credit	(D)	(49,341)	(600)	(2,179)	(52,120)	W/S 4A,4B,4C line 5	(1)
18		Property Tax Expense	(E)	5,226,750	2,236,785	1,145,707	8,609,242	W/S 4A,4B,4C line 8	(1)
19		Payroll Tax Expense	(F)	37,155	(505)	1,120	37,770	W/S 4A,4B,4C line 20	(1)
20		Operation & Maintenance Expense	(G)	4,360,357	1,271,570	389,810	6,021,737	W/S 4A,4B,4C line 16	(1)
21		Administrative & General Expense	(H)	5,109,811	1,462,936	611,174	7,183,921	W/S 4A,4B,4C line 19	(2)
22		Transmission Related Integrated Facilities Charge	(I)	-	-	-	-	N/A	(1)
23		Transmission Support Revenue	(J)	(2,917,925)	(376,198)	-	(3,294,123)	W/S 7	(1)
24		Transmission Support Expense	(K)	1,625,568	880,469	357,869	2,863,906	W/S 7	(1)
25		Transmission Related Expense from Generators	(L)	-	-	-	-	N/A	(1)
26		Transmission Related Taxes and Fees Charge	(M)	1,135,268	19,553	1,263	1,156,084	Attachment B, line 14	(1)
27		Revenue for ST Trans. Service Under the OATT	(N)	(68,394)	(16,040)	(8,880)	(93,314)	Attachment C, line 9	(1)
28		Transmission Rents Received from Electric Property	(O)	(5,239,993)	(1,821,957)	(402,030)	(7,463,980)	Attachment C1, line 3	(1)
29		Total Revenue Requirements (Line 14 thru 28)		50,323,640	13,578,244	7,542,413	71,444,297		(2)

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.

(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

CL&P, PSNH and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Post-1996
Worksheet 1B

LN.		(A)	Attachment F Reference Section:	(B) CL&P	(C) PSNH	(D) WMECO	(E)=(B)+(C)+(D) Total	(F) Reference	(G) Notes
	I.	INVESTMENT BASE							
1		Transmission Plant	(A)(1)(a)	2,415,403,244	568,289,707	717,553,491	3,701,246,442	W/S 3A,3B,3C line 1	(1)
2		General Plant	(A)(1)(b)	80,962,316	47,073,591	15,532,275	143,568,182	W/S 3A,3B,3C line 2	(1)
3		Plant Held For Future Use	(A)(1)(c)	566,521	7,304,557	-	7,871,078	W/S 3A,3B,3C line 4	(1)
4		Total Plant (Lines 1+2+3)		2,496,932,081	622,667,855	733,085,766	3,852,685,702		(1)
5		Accumulated Depreciation	(A)(1)(d)	491,696,956	110,515,089	48,472,669	650,684,714	W/S 3A,3B,3C line 7	(1)
6		Accumulated Deferred Income Taxes	(A)(1)(e)	330,565,024	108,344,471	182,063,297	620,972,792	W/S 3A,3B,3C line 10	(1)
7		Loss On Reacquired Debt	(A)(1)(f)	4,198,950	1,574,739	273,655	6,047,344	W/S 3A,3B,3C line 11	(1)
8		Other Regulatory Assets	(A)(1)(g)	26,432,426	9,107,309	10,893,168	46,432,903	W/S 3A,3B,3C line 16	(2)
9		Net Investment (Line 4-5-6+7+8)		1,705,301,477	414,490,343	513,716,623	2,633,508,443		(2)
10		Prepayments	(A)(1)(h)	12,693,335	4,251,680	846,180	17,791,195	W/S 3A,3B,3C line 17	(1)
11		Materials & Supplies	(A)(1)(i)	30,614,229	8,092,403	2,598,082	41,304,714	W/S 3A,3B,3C line 18	(1)
12		Cash Working Capital	(A)(1)(j)	7,968,775	2,193,295	1,689,378	11,851,448	W/S 3A,3B,3C line 24	(2)
13		Total Investment Base Excluding CWIP (Line 9+10+11+12)		1,756,577,816	429,027,721	518,850,263	2,704,455,800		(2)
14		NEEWS Construction Work In Progress	(A)(1)(l)	164,948,530		-	164,948,530	(a)	(1)
15		Total Investment Base Including CWIP (Line 13+14)		1,921,526,346	429,027,721	518,850,263	2,869,404,330		(2)
	II.	REVENUE REQUIREMENTS							
16		Investment Return and Income Taxes	(A)	218,293,438	51,108,785	59,601,367	329,003,590	W/S 2A,2B,2C, line 15	(2)
17		Investment Return and Income Taxes-CWIP		20,498,484	-	-	20,498,484	W/S 2A,2B,2C, line 15	(1)
18		Depreciation Expense	(B)	57,857,303	12,315,183	13,853,324	84,025,810	W/S 4A,4B,4C line 3	(1)
19		Amortization of Loss on Reacquired Debt	(C)	460,401	195,905	41,048	697,354	W/S 4A,4B,4C line 4	(1)
20		Investment Tax Credit	(D)	(332,148)	(3,850)	(29,425)	(365,423)	W/S 4A,4B,4C line 5	(1)
21		Property Tax Expense	(E)	35,184,843	14,352,660	15,469,033	65,006,536	W/S 4A,4B,4C line 8	(1)
22		Payroll Tax Expense	(F)	250,119	(3,240)	15,117	261,996	W/S 4A,4B,4C line 20	(1)
23		Operation & Maintenance Expense	(G)	29,352,552	8,159,213	5,263,108	42,774,873	W/S 4A,4B,4C line 16	(1)
24		Administrative & General Expense	(H)	34,397,650	9,387,146	8,251,915	52,036,711	W/S 4A,4B,4C line 19	(2)
25		Transmission Related Integrated Facilities Charge	(I)	-	-	-	-	N/A	(1)
26		Transmission Related Expense from Generators	(L)	-	-	-	-	N/A	(1)
27		Transmission Related Taxes and Fees Charge	(M)	7,642,269	125,466	17,047	7,784,782	Attachment B line 16	(1)
28		Revenue for ST Trans. Service Under the OATT	(N)	(460,565)	(102,948)	(119,820)	(683,333)	Attachment C line 10	(1)
29		Total Revenue Requirements (Line 16 thru 28)		403,144,346	95,534,320	102,362,714	601,041,380		(2)

(a) Reflects actual information per Eversource's accounting records

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

CL&P, PSNH and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Post-2003
Worksheet 1C

LN.	(A) I. INVESTMENT BASE	(B) CL&P	(C) PSNH	(D) WMECO	(E)=(B)+(C)+(D) TOTAL	(F) REFERENCE	(G) Notes
1	Transmission Plant	$ 1,535,579,816	$ 124,215,608	$ 12,384,353	$ 1,672,179,777	Attachment D, D2, D4	(1)
2	Accumulated Depreciation	$ 213,218,089	$ 18,074,549	$ 1,442,093	$ 232,734,731	Attachment D, D2, D4	(1)
3	Accumulated Deferred Income Taxes	$ 155,340,565	$ 15,930,789	$ 2,675,475	$ 173,946,829	Attachment D1, D3, D5	(1)
4	Net Investment (Line 1-2-3)	$ 1,167,021,162	$ 90,210,270	$ 8,266,785	$ 1,265,498,217		(1)
	II. INCREMENTAL RETURN						
5	Incremental Revenue Requirements	$ 6,906,431	$ 545,953	$ 47,005	$ 7,499,389	W/S 2A,2B,2C Post 2003	(1)

Note: ROE incentives approved in FERC Opinion No. 489. As a result of Opinion No. 531-B, these projects receive an ROE incentive of 67 bp.

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.

CL&P, PSNH and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
NEEWS
Worksheet 1E

LN.	(A) I. INVESTMENT BASE	(B) CL&P	(C) WMECO	(D) = (B) + (C) Total	(E) REFERENCE	(F) Notes
1	Transmission Plant	$ 200,288,632	$ 556,313,751	$ 756,602,383	Attachment F & F2	(1)
2	Accumulated Depreciation	$ 8,946,318	$ 22,283,705	$ 31,230,023	Attachment F & F2	(1)
3	Accumulated Deferred Income Taxes	$ 46,929,968	$ 142,742,742	$ 189,672,710	Attachment F1 & F3	(1)
4	Net Investment Excluding CWIP (Line 1-2-3)	$ 144,412,346	$ 391,287,304	$ 535,699,650		(1)
5	NEEWS Construction Work In Progress	$ 164,948,530	$ -	$ 164,948,530	Attachment F & F2	(1)
6	Net Investment Including CWIP (Line 4+5)	$ 309,360,876	$ 391,287,304	$ 700,648,180		(1)
	II. INCREMENTAL RETURN					
7	Incremental Revenue Requirements	$ 854,632	$ 2,224,860	$ 3,079,492	W/S 2A & 2C NEEWS	(1)
8	Incremental Revenue Requirements-CWIP	$ 976,165	$ -	$ 976,165	W/S 2A & 2C NEEWS	(1)
9	Total Incremental Revenue Requirements (line 7+8)	$ 1,830,797	$ 2,224,860	$ 4,055,657		(1)

Note: Incentives approved in FERC Docket No. ER08-1548. As a result of Opinion No. 531-B, this project receives ROE incentives of 67 bp.

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.

Connecticut Light & Power Company (CL&P)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Investment Return and Income Taxes - Pre 1997
Worksheet 2A

Line	(A)	(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 2,579,060,322	45.78%	5.36%	2.45%		
2	PREFERRED STOCK	$ 116,868,097	2.07%	4.80%	0.10%	0.10%	
3	COMMON EQUITY	$ 2,938,441,767	52.15%	11.07%	5.77%	5.77%	
4	TOTAL INVESTMENT RETURN	$ 5,634,370,186	100.00%		8.32%	5.87%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.0832

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit (W/S 1A) + Eq. AFUDC of Deprec. Exp. (Att. I)) / PTF Inv. Base (W/S 1A) x Federal Income Tax Rate)
(1 - Federal Income Tax Rate)

6 = 0.0587 +((49,341) + 269,748) / 260,943,025) x 0.35)
7 (1 - 0.35)

8 = 0.032063

(c) State Income Tax = R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate
(1 - State Income tax Rate)

9 = 0.0587 +((49,341) + 269,748) / 260,943,025) + 0.032063)* 0.09
10 (1 - 0.09)

11 = 0.009060

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.124323

Line		**Pre-1997 PTF**	
13	INVESTMENT BASE	$ 260,943,025	From Worksheet 1A, line 13
14	x Cost of Capital Rate	0.124323	
15	= Investment Return and Income Taxes	$ 32,441,220	To Worksheet 1A, line 14

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Connecticut Light & Power Company (CL&P)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Investment Return and Income Taxes - Post 1996
Worksheet 2A

Line	(A)	(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 2,579,060,322	45.78%	5.36%	2.45%		
2	PREFERRED STOCK	$ 116,868,097	2.07%	4.80%	0.10%	0.10%	
3	COMMON EQUITY	$ 2,938,441,767	52.15%	11.07%	5.77%	5.77%	
4	TOTAL INVESTMENT RETURN	$ 5,634,370,186	100.00%		8.32%	5.87%	

Cost of Capital Rate=

Line													
5	(a) Weighted Cost of Capital	=	0.0832										
	(b) Federal Income Tax	= (	R.O.E. +	(	PTF Inv. (Tax Credit (W/S 1B)	+	Eq. AFUDC of Deprec. Exp. (Att. I)	) /	PTF Inv. Base (W/S 1B)	x	Federal Income Tax Rate)		
							(1 - Federal Income Tax Rate)						
6		=	0.0587	+(	(332,148)	+	1,815,862	) /	1,921,526,346	)	x	0.35)	
7						(	1	-	0.35	)			
8		=	0.032023										
	(c) State Income Tax	=	R.O.E. +	(	PTF Inv. (Tax Credit	+	Eq. AFUDC of Deprec. Exp.	) /	PTF Inv. Base)	+	Federal Income Tax)*State Income Tax Rate		
							(1 - State Income tax Rate)						
9		=	0.0587	+(	(332,148)	+	1,815,862	) /	1,921,526,346	)	+	0.032023)*	0.09
10						(	1	-	0.09	)			
11		=	0.009049										
12	(a)+(b)+(c) Cost of Capital Rate	=	0.124272										

Line		Post - 1996 Total PTF	-	Post - 1996 PTF CWIP	=	Post -1996 PTF Excluding CWIP	
13	INVESTMENT BASE	$ 1,921,526,346		$ 164,948,530		$ 1,756,577,816	From Worksheet 1B, line 13, 14
14	x Cost of Capital Rate	0.124272		0.124272		0.124272	
15	= Investment Return and Income Taxes	$ 238,791,922		$ 20,498,484		$ 218,293,438	To Worksheet 1B, line 16

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Connecticut Light & Power Company (CL&P)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Investment Return and Income Taxes - 50bp

Line	(A)		(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$	2,579,060,322	45.78%		0.00%		
2	PREFERRED STOCK	$	116,868,097	2.07%		0.00%	0.00%	
3	COMMON EQUITY	$	2,938,441,767	52.15%	0.50%	0.26%	0.26%	
4	TOTAL INVESTMENT RETURN	$	5,634,370,186	100.00%		0.26%	0.26%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.0026

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit (W/S 1B) + Eq. AFUDC of Deprec. Exp. (Att. I)) / PTF Inv. Base (W/S 1B) x Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

6 = 0.0026 +(0 + 0) / 2,182,469,371) x 0.35)
7 (1 - 0.35)

8 = 0.001400

(c) State Income Tax = R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate / (1 - State Income tax Rate)

9 = 0.0026 +(0 + 0) / 2,182,469,371) + 0.001400)* 0.09
10 (1 - 0.09)

11 = 0.000396

12 (a)+(b)+(c) Cost of Capital Rate = 0.004396

Line			Total PTF
13	INVESTMENT BASE	$	2,182,469,371
14	x Cost of Capital Rate		0.004396
15	= Investment Return and Income Taxes	$	9,594,135

Notes:

(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-224, Schedule 1, Page 2 of 4, Line 14
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Connecticut Light & Power Company (CL&P)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Worksheet 3A

LN.		(1) Transmission	(2) Wage/Plant Allocation Factors (a)	(3) Transmission	Pre-1997 PTF (4) PTF Allocation Factor (b)	Pre-1997 PTF (5) = (3)*(4) PTF Allocated	Post-1996 PTF (6) PTF Allocation Factor (b)	Post-1996 PTF (7) = (3)*(6) PTF Allocated	Reference	Notes
	Transmission Plant									
1	Transmission Plant					358,812,326		2,415,403,244	Attachment A (H1)	(1)
2	General Plant	104,400,554		104,400,554	11.5201%	12,027,048	77.5497%	80,962,316	FF1 page 204 ln. 99, footnote	(1)
3	Total (line 1+2)	104,400,554		104,400,554		370,839,374		2,496,365,560		(1)
										(1)
4	Transmission Plant Held for Future Use	730,526	(c)	730,526	11.5201%	84,157	77.5497%	566,521	(c)	(1)
	Transmission Accumulated Depreciation									
5	Transmission Accum. Depreciation	605,238,764		605,238,764	11.5201%	69,724,111	77.5497%	469,360,846	FF1 page 219 ln. 25	(1)
6	General Plant Accum. Depreciation	28,802,317		28,802,317	11.5201%	3,318,056	77.5497%	22,336,110	FF1 page 219 ln. 28, footnote	(1)
7	Total (line 5+6)	634,041,081		634,041,081		73,042,167		491,696,956	Schedule 2, Page 6,7,8	(1)
	Transmission Accumulated Deferred Taxes									
8	Accumulated Deferred Taxes (281 to 283)	(470,775,688)		(470,775,688)	11.5201%	(54,233,830)	77.5497%	(365,085,134)	FF1 page 274 ln. 9 & 276 ln. 19 fns	(1)
9	Accumulated Deferred Taxes (190)	44,513,531	(d)	44,513,531	11.5201%	5,128,003	77.5497%	34,520,110	(d)	(1)
10	Total (line 8+9)	(426,262,157)		(426,262,157)		(49,105,827)		(330,565,024)		(1)
11	Transmission loss on Reacquired Debt	5,414,528		5,414,528	11.5201%	623,759	77.5497%	4,198,950	FF1 page 110 ln. 81, footnote	(1)
	Other Regulatory Assets									
12	Unamortized Balance of Transmission Merger-Related Costs	14,306,651		14,306,651	11.5201%	1,648,141	77.5497%	11,094,765	Exhibit No. ES-220, Page 1 of 8, Line 3(B)	(2)
13	FAS 106	66,791		66,791	11.5201%	7,694	77.5497%	51,796	FF1 page 232 Ln. 27, footnote	(1)
14	FAS 109	23,019,567		23,019,567	11.5201%	2,651,877	77.5497%	17,851,605	FF1 page 232 ln. 7, footnote	(1)
15	Other Regulatory Liabilities (254.DK)	(3,308,510)		(3,308,510)	11.5201%	(381,144)	77.5497%	(2,565,740)	FF1 page 278 ln. 3, footnote	(1)
16	Total (line 12+13+14)	34,084,499		34,084,499		3,926,568		26,432,426		(2)
17	Transmission Prepayments (165)	16,368,000		16,368,000	11.5201%	1,885,610	77.5497%	12,693,335	FF1 page 110 ln. 57, footnote	(1)
18	Transmission Materials and Supplies	39,476,915		39,476,915	11.5201%	4,547,780	77.5497%	30,614,229	FF1 page 227 ln. 8	(1)
	Cash Working Capital									
19	Operation & Maintenance Expense					4,360,357		29,352,552	W/S 4A, Line 16	(1)
20	Administrative & General Expense					5,109,811		34,397,650	W/S 4A, Line 19	(3)
21	Transmission Support Expense					-		-	W/S 7	(1)
22	Subtotal (line 18+19+20)					9,470,168		63,750,202		(3)
23						0.125		0.125	x 45 / 360	(1)
24	Total (line 21 * line 22)					1,183,771		7,968,775		(3)

(a) All items are specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries and Plant Allocation Factors are not used (colum
(b) W/S 5A & 5B

(c)	Account 105	32,127,498	FF1 page 214 ln. 33	(1)
	Less Third Underground Conduit Duct	31,396,972	FF1 page 214 ln. 22	(1)
		730,526		(1)
(d)	Account 190	46,955,376	FF1 page 234 ln. 18, footnote	(1)
	Less Reserve for Disputed Transactions	2,441,845	FF1 page 234 ln. 18, footnote	(1)
	Total Account 190	44,513,531		(1)

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Proposed revisions reflect the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset
(3) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Connecticut Light & Power Company (CL&P)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Worksheet 4A

					PRE-97 PTF		POST-96 PTF			
		(1)	(2) Wage/Plant Allocation	(3)	(4) PTF Allocation	(5) = (3)*(4) PTF	(6) PTF Allocation	(7) = (3)*(6) Post-96 PTF		
LN.		Transmission	Factors (a)	Transmission	Factor (b)	Allocated	Factor (b)	Allocated	Reference	Notes
	Depreciation Expense									
1	Transmission Depreciation	69,626,166		69,626,166	11.5201%	8,021,004	77.5497%	53,994,883	FF1 page 336 ln. 7	(1)
2	General Depreciation	4,980,574		4,980,574	11.5201%	573,767	77.5497%	3,862,420	FF1 page 336 ln. 10, footnote	(1)
3	Total (line 1+2)	74,606,740		74,606,740		8,594,771		57,857,303		(1)
4	Amortization of Loss on Reacquired Debt	593,685		593,685	11.5201%	68,393	77.5497%	460,401	FF1 page 114 ln. 64, footnote	(1)
5	Amortization of Investment Tax Credits	428,304		428,304	11.5201%	49,341	77.5497%	332,148	FF1 page 266 ln. 8(f), footnote	(1)
	Property Taxes									
6	Transmission Property Taxes	45,370,701		45,370,701	11.5201%	5,226,750	77.5497%	35,184,843	FF1 page 262 ln. 25i, footnote	(1)
7	General Property Taxes (c)	-		-	11.5201%	-	77.5497%	-		(1)
8	Total (line 6+7)	45,370,701		45,370,701		5,226,750		35,184,843		(1)
	Transmission Operation and Maintenance									
9	Operation and Maintenance	77,432,007		77,432,007	11.5201%	8,920,245	77.5497%	60,048,289	FF1 page 321 ln. 112	(1)
10	Transmission of Electricity by Others - #565	21,727,966		21,727,966	11.5201%	2,503,083	77.5497%	16,849,972	FF1 page 321 ln. 96	(1)
11	Account 561.1	3,245,594		3,245,594	11.5201%	373,896	77.5497%	2,516,948	FF1 page 321 ln. 85	(1)
12	Account 561.2	5,212,556		5,212,556	11.5201%	600,492	77.5497%	4,042,322	FF1 page 321 ln. 86	(1)
13	Account 561.3	2,238,612		2,238,612	11.5201%	257,890	77.5497%	1,736,037	FF1 page 321 ln. 87	(1)
14	Account 561.4	7,157,291		7,157,291	11.5201%	824,527	77.5497%	5,550,458	FF1 page 321 ln. 88	(1)
15	**Station Expenses & Rents	-		-	11.5201%	-	77.5497%	-	FF1 page 321 ln. 93 + ln. 98	(1)
16	O&M less lines 10 thru 15	37,849,988		37,849,988		4,360,357		29,352,552		(1)
	Transmission Administrative and General									
17	Administrative and General	37,202,294		37,202,294	11.5201%	4,285,741	77.5497%	28,850,267	FF1 page 320 ln. 197 b, footnote	(1)
18	Transmission Merger-Related Costs	7,153,326		7,153,326	11.5201%	824,070	77.5497%	5,547,383	**Exhibit No. ES-220, Page 1 of 8, Line 2(B)**	(2)
19	Total (line 17 + 18)					5,109,811		34,397,650		(2)
20	*Payroll Tax Expense*	322,527		322,527	11.5201%	37,155	77.5497%	250,119		(1)
	Federal Unemployment	5,226							FF1 page 262 ln. 3i, footnote	(1)
	FICA	233,351							FF1 page 262 ln. 5i, footnote	(1)
	Medicare	65,613							FF1 page 262 ln. 9i, footnote	(1)
	CT Unemployment	16,786							FF1 page 262 ln. 15i, footnote	(1)
	DC Unemployment	11							FF1 page 262.1 ln. 14i, footnote	(1)
	FL Unemployment	1							FF1 page 262.1 ln. 18i, footnote	(1)
	GA Unemployment	-							FF1 page 262 footnote	(1)
	MA Unemployment	(285)							FF1 page 262 ln. 32i, footnote	(1)
	MA Universal Health	64							FF1 page 262 ln. 33i, footnote	(1)
	MI Unemployment	6							FF1 page 262.1 ln. 22i, footnote	(1)
	NH Unemployment	1,754							FF1 page 262.1 ln. 4i, footnote	(1)
	NJ Unemployment	-							FF1 page 262 footnote	(1)
	NY Unemployment	-							FF1 page 262.1 ln. 10i, footnote	(1)
	Total	322,527	To Line 18							(1)

** To the extent that PTF Support Payments are reflected in worksheet 7 they will be excluded from this calculation.

(a) All items are specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries and Plant Allocation Factors are not used (column 2).

(b) W/S 5A & 5B

(c) Transmission related general property taxes are included in the Transmission Property tax number footnoted in the FF1.

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.

(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Public Service Company of New Hampshire (PSNH)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Investment Return and Income Taxes - Pre 1997
Worksheet 2B

Line	(A)	(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 1,070,020,120	46.56%	4.15%	1.93%		
2	PREFERRED STOCK	$ -	0.00%	0.00%	0.00%	0.00%	
3	COMMON EQUITY	$ 1,228,095,985	53.44%	11.07%	5.92%	5.92%	
4	TOTAL INVESTMENT RETURN	$ 2,298,116,105	100.00%		7.85%	5.92%	

Cost of Capital Rate=

Line										
5	(a) Weighted Cost of Capital	=	0.0785							
	(b) Federal Income Tax	=(	(R.O.E. +	(PTF Inv. (Tax Credit (W/S 1A) +	Eq. AFUDC of Deprec. Exp. (Att. I)	) /	PTF Inv. Base (W/S 1A)	x	Federal Income Tax Rate)	
					(1 - Federal Income Tax Rate)					
6		=(	0.0592	+((600) +	29,005	) /	66,924,472)	x	0.35)	
7					(1	-	0.35)			
8		=	0.032105							
	(c) State Income Tax	=(	R.O.E. +	+(PTF Inv. (Tax Credit +	Eq. AFUDC of Deprec. Exp.	) /	PTF Inv. Base)	+	Federal Income Tax)*State Income Tax Rate	
					(1 - State Income Tax Rate)					
9		=(	0.0592	+((600) +	29,005	) /	66,924,472)	+	0.032105)*	0.085
10					(1	-	0.085)			
11		=	0.008521							
12	(a)+(b)+(c) **Cost of Capital Rate**	=	0.119126							

Line		**Pre-1997 PTF**	
13	INVESTMENT BASE	$ 66,924,472	From Worksheet 1A, line 13
14	x Cost of Capital Rate	0.1191260	
15	= Investment Return and Income Taxe	$ 7,972,445	To Worksheet 1A, line 14

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-00
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expens

Public Service Company of New Hampshire (PSNH)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Investment Return and Income Taxes - Post 1996
Worksheet 2B

Line	(A)	(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 1,070,020,120	46.56%	4.15%	1.93%		
2	PREFERRED STOCK	$ -	0.00%	0.00%	0.00%	0.00%	
3	COMMON EQUITY	$ 1,228,095,985	53.44%	11.07%	5.92%	5.92%	
4	TOTAL INVESTMENT RETURN	$ 2,298,116,105	100.00%		7.85%	5.92%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.0785

(b) Federal Income Tax = ((R.O.E. + (PTF Inv. (Tax Credit (W/S 1B) + Eq. AFUDC of Deprec. Exp. (Att. I)) / PTF Inv. Base (W/S 1A) x Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

6 = (0.0592 +((3,850) + 186,109) / 429,027,721) x 0.35)
7 / (1 - 0.35)

8 = 0.032106

(c) State Income Tax = (R.O.E. + +(PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate / (1 - State Income Tax Rate)

9 = (0.0592 +((3,850) + 186,109) / 429,027,721) + 0.032106)* 0.085
10 / (1 - 0.085)

11 = 0.008521

12 (a)+(b)+(c) Cost of Capital Rate = 0.119127

Line		Post - 1996Total PTF	
13	INVESTMENT BASE	$ 429,027,721	From Worksheet 1A, line 13
14	x Cost of Capital Rate	0.119127	
15	= Investment Return and Income Taxe	$ 51,108,785	To Worksheet 1B, line 16

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-00
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expens

Public Service Company of New Hampshire (PSNH)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Investment Return and Income Taxes - 50bp

Line	(A)	(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 1,070,020,120	46.56%		0.00%		
2	PREFERRED STOCK	$ -	0.00%		0.00%	0.00%	
3	COMMON EQUITY	$ 1,228,095,985	53.44%	0.50%	0.27%	0.27%	
4	TOTAL INVESTMENT RETURN	$ 2,298,116,105	100.00%		0.27%	0.27%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.0027

(b) Federal Income Tax = ((R.O.E. + (PTF Inv. (Tax Credit (W/S 1B) + Eq. AFUDC of Deprec. Exp. (Att. I)) / PTF Inv. Base (W/S 1A) x Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

6 = (0.0027 +(0 + 0) / 495,952,193) x 0.35)
7 (1 - 0.35)

8 = 0.001454

(c) State Income Tax = (R.O.E. + +(PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate / (1 - State Income Tax Rate)

9 = (0.0027 +(0 + 0) / 495,952,193) + 0.001454)* 0.085
10 (1 - 0.085)

11 = 0.000386

12 (a)+(b)+(c) Cost of Capital Rate = 0.004540

Line		Total PTF
13	INVESTMENT BASE	$ 495,952,193
14	x Cost of Capital Rate	0.004540
15	= Investment Return and Income Taxe	$ 2,251,623

Notes:

(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-224, Schedule 1, Page 2 of 4, Line
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expens

Public Service Company of New Hampshire (PSNH)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Worksheet 3B

					Pre-1997 PTF		Post-1996 PTF			
LN.		(1) Transmission	(2) Wage/Plant Allocation Factors (a)	(3) Transmission	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	(6) PTF Allocation Factor (b)	(7) = (3)*(6) Post-96 PTF Allocated	Reference	Notes
	Transmission Plant									
1	Transmission Plant					88,564,672		568,289,707	Attachment A1	(1)
2	General Plant	59,322,426		59,322,426	12.3666%	7,336,167	79.3521%	47,073,591	FF1 page 204 ln. 99, footnote	(1)
3	Total (line 1+2)	59,322,426		59,322,426		95,900,839		615,363,298		(1)
										(1)
4	Transmission Plant Held for Future Use	9,205,247		9,205,247	12.3666%	1,138,376	79.3521%	7,304,557	FF1 page 214 ln. 35	(1)
	Transmission Accumulated Depreciation									
5	Transmission Accum. Depreciation	123,132,357		123,132,357	12.3666%	15,227,286	79.3521%	97,708,111	FF1 page 219 ln. 25	(1)
6	General Plant Accum. Depreciation	16,139,432		16,139,432	12.3666%	1,995,899	79.3521%	12,806,978	FF1 page 219 ln. 28, footnote	(1)
7	Total (line 5+6)	139,271,789		139,271,789		17,223,185		110,515,089		(1)
	Transmission Accumulated Deferred Taxes									
8	Accumulated Deferred Taxes (281-283)	(145,475,861)		(145,475,861)	12.3666%	(17,990,418)	79.3521%	(115,438,151)	FF1 page 274 ln. 9 & 276 ln. 19 fns	(1)
9	Accumulated Deferred Taxes (190)	8,939,499 (c)		8,939,499	12.3666%	1,105,512	79.3521%	7,093,680	(c)	(1)
10	Total (line 8+9)	(136,536,362)		(136,536,362)		(16,884,906)				
				-						
11	Transmission loss on Reacquired Debt	1,984,496		1,984,496	12.3666%	245,415	79.3521%	1,574,739	FF1 page 110 ln. 81, footnote	(1)
	Other Regulatory Assets									
12	Unamortized Balance of Transmission Merger-Related Costs	2,963,245		2,963,245	0.123666	366,453	0.793521	2,351,397	**Exhibit No. ES-220, Page 3 of 8, Line 3(B)**	(2)
13	FAS 106	350,591		350,591	12.3666%	43,356	79.3521%	278,201	FF1 page 232.1 ln. 15, footnote	(1)
14	FAS 109	8,171,016		8,171,016	12.3666%	1,010,477	79.3521%	6,483,873	FF1 page 232 ln. 1, footnote	(1)
15	Other Regulatory Liabilities (254.DK)	(7,765)		(7,765)	12.3666%	(960)	79.3521%	(6,162)	FF1 page 278 ln. 1, footnote	(1)
16	Total (line 12+13+14)	11,477,087		11,477,087		1,419,326		9,107,309		(2)
17	Transmission Prepayments	5,357,993		5,357,993	12.3666%	662,602	79.3521%	4,251,680	FF1 page 110 ln. 57, footnote	(1)
18	Transmission Materials and Supplies	10,198,096		10,198,096	12.3666%	1,261,158	79.3521%	8,092,403	FF1 page 227 ln. 8	(1)
	Cash Working Capital									
19	Operation & Maintenance Expense					1,271,570		8,159,213	W/S 4B, Line 16	(1)
20	Administrative & General Expense					1,462,936		9,387,146	W/S 4B, Line 19	(3)
21	Transmission Support Expense					504,271		-	W/S 7	(1)
22	Subtotal (line 18+19+20)					3,238,777		17,546,359		(3)
23						0.125		0.125	x 45 / 360	(1)
24	Total (line 21 * line 22)					404,847		2,193,295		(3)

(a) All items are specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries and Plant Allocation Factors are not used (column 2).
(b) W/S 5A & 5B
(c)

Account 190	8,939,499	FF1 page 234 ln. 18, footnote	(1)
Less Reserve for Disputed Transactions	-	FF1 page 234 ln. 18, footnote	(1)
Total Account 190	8,939,499		(1)

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Proposed revisions reflect the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset
(3) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expense

Public Service Company of New Hampshire (PSNH)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Worksheet 4B

LN.		(1) Transmission	(2) Wage/Plant Allocation Factors (a)	(3) Transmission	Pre-1997 PTF (4) PTF Allocation Factor (b)	Pre-1997 PTF (5) = (3)*(4) PTF Allocated	Post-1996 PTF (6) PTF Allocation Factor (b)	Post-1996 PTF (7) = (3)*(6) Post-96 PTF Allocated	Reference	Notes
	Depreciation Expense									
1	Transmission Depreciation	12,792,512		12,792,512	12.3666%	1,581,999	79.3521%	10,151,127	FF 1 page 336 ln. 7	(1)
2	General Depreciation	2,727,156		2,727,156	12.3666%	337,256	79.3521%	2,164,056	FF1 page 336 ln. 10, footnote	(1)
3	Total (line 1+2)	15,519,668		15,519,668		1,919,255		12,315,183		(1)
4	Amortization of Loss on Reacquired Debt	246,881		246,881	12.3666%	30,531	79.3521%	195,905	FF1 page 114 ln. 64, footnote	(1)
5	Amortization of Investment Tax Credits	4,852		4,852	12.3666%	600	79.3521%	3,850	FF1 page 266 ln. 8(f), footnote	(1)
	Property Taxes									
6	Transmission Property Taxes	18,087,310		18,087,310	12.3666%	2,236,785	79.3521%	14,352,660	FF1 page 262 ln. 23i + ln. 30i +	(1)
7	General Property Taxes (c)	-		-	12.3666%	-	79.3521%	-	page 262.1 ln. 2i, footnote	(1)
8	Total (line 6+7)	18,087,310		18,087,310		2,236,785		14,352,660		(1)
	Transmission Operation and Maintenance									
9	Operation and Maintenance	51,082,852		51,082,852	12.3666%	6,317,212	79.3521%	40,535,316	FF1 page 321 ln. 112	(1)
10	Transmission of Electricity by Others - #565	37,174,569		37,174,569	12.3666%	4,597,230	79.3521%	29,498,801	FF1 page 321 ln. 96	(1)
11	Account 561.1	653,575		653,575	12.3666%	80,825	79.3521%	518,625	FF1 page 321 ln. 85	(1)
12	Account 561.2	474,690		474,690	12.3666%	58,703	79.3521%	376,676	FF1 page 321 ln. 86	(1)
13	Account 561.3	36,962		36,962	12.3666%	4,571	79.3521%	29,330	FF1 page 321 ln. 87	(1)
14	Account 561.4	2,460,768		2,460,768	12.3666%	304,313	79.3521%	1,952,671	FF1 page 321 ln. 88	(1)
15	**Station Expenses & Rents	-		-	12.3666%	-	79.3521%	-	FF1 page 321 ln. 93 + ln. 98	(1)
16	O&M less lines 10 thru 15	10,282,288		10,282,288		1,271,570		8,159,213		(1)
	Transmission Administrative and General									
17	Administrative and General	10,348,117		10,348,117	12.3666%	1,279,710	79.3521%	8,211,448	FF1 page 320 ln. 197 b, footnote	(1)
18	Transmission Merger-Related Costs	1,481,622		1,481,622	12.3666%	183,226	79.3521%	1,175,698	**Exhibit No. ES-220, Page 3 of 8, Line 2(B)**	(2)
19	Total (line 17 + 18)					1,462,936		9,387,146		(2)
20	*Payroll Tax Expense*	(4,083)		(4,083)	12.3666%	(505)	79.3521%	(3,240)		(1)
	Federal Unemployment	(51)							FF1 page 262 ln. 2i, footnote	(1)
	FICA	(3,062)							FF1 page 262 ln. 4i, footnote	(1)
	Medicare	(816)							FF1 page 262 ln. 7i, footnote	(1)
	CT Unemployment	(128)							FF1 page 262.1 ln. 7i, footnote	(1)
	DC Unemployment	0							FF1 page 262 ln. 26i, footnote	(1)
	FL Unemployment	0							FF1 page 262.1 ln. 27i, footnote	(1)
	GA Unemployment	0							FF1 page 262.1, footnote	(1)
	MA Unemployment	2							FF1 page 262.1 ln. 15i, footnote	(1)
	MA Universal Health	(1)							FF1 page 262.1 ln. 16i, footnote	(1)
	MI Unemployment	0							FF1 page 262.1 ln. 31i, footnote	(1)
	NH Unemployment	(27)							FF1 page 262 ln. 14i, footnote	(1)
	NJ Unemployment	0							FF1 page 262, footnote	(1)
	NY Unemployment	0							FF1 page 262 footnote	(1)
	Total	(4,083)	To Line 19							(1)

** To the extent that PTF Support Payments are reflected in worksheet 7 they will be excluded from this calculation.
(a) All items are specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries and Plant Allocation Factors are not used (column 2).
(b) W/S 5A & 5B
(c) Transmission related general property taxes are included in the Transmission Property tax number footnoted in the FF1.

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-00
(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expense

Western Massachusetts Electric Company (WMECO)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Investment Return and Income Taxes - Pre 1997
Worksheet 2C

Line	(A)	(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 567,833,428	49.55%	4.31%	2.14%		
2	PREFERRED STOCK	$ -	0.00%	0.00%	0.00%	0.00%	
3	COMMON EQUITY	$ 578,162,814	50.45%	11.07%	5.58%	5.58%	
4	TOTAL INVESTMENT RETURN	$ 1,145,996,242	100.00%		7.72%	5.58%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.0772

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit (W/S 1A) + Eq. AFUDC of Deprec. Exp. (Att. I)) / PTF Inv. Base (W/S 1A) x Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

6 = (0.0558 +((2,179) + 11,396) / 38,473,076) x 0.35)
7 (1 - 0.35)

8 = 0.030175

(c) State Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate / (1 - State Income Tax Rate)

9 = (0.0558 +((2,179) + 11,396) / 38,473,076) + 0.030175)* 0.08
10 (1 - 0.08)

11 = 0.007497

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.114872

Line		**Pre-1997 PTF**	
13	INVESTMENT BASE	$ 38,473,076	From Worksheet 1A, line 13
14	x Cost of Capital Rate	0.114872	
15	= Investment Return and Income Taxes	$ 4,419,479	To Worksheet 1A, line 14

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Western Massachusetts Electric Company (WMECO)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014

Investment Return and Income Taxes - Post 1996

Worksheet 2C

Line	(A)	(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 567,833,428	49.55%	4.31%	2.14%		
2	PREFERRED STOCK	$ -	0.00%	0.00%	0.00%	0.00%	
3	COMMON EQUITY	$ 578,162,814	50.45%	11.07%	5.58%	5.58%	
4	TOTAL INVESTMENT RETURN	$ 1,145,996,242	100.00%		7.72%	5.58%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.0772

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit (W/S 1B) + Eq. AFUDC of Deprec. Exp. (Att. I)) / PTF Inv. Base (W/S 1B) x Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

6 = (0.0558 +((29,425) + 153,859) / 518,850,263) x 0.35)
7 (1 - 0.35)

8 = 0.030175

(c) State Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate / (1 - State Income Tax Rate)

9 = (0.0558 +((29,425) + 153,859) / 518,850,263) + 0.030175)* 0.08
10 (1 - 0.08)

11 = 0.007497

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.114872

Line		**Post - 1996 Total PTF**	-	**Post - 1996 PTF CWIP**	=	**Post -1996 PTF Excluding CWIP**	
13	INVESTMENT BASE	$ 518,850,263		$ -		$ 518,850,263	From Worksheet 1B, line 13, 14
14	x Cost of Capital Rate	0.1148720		0.1148720		0.1148720	
15	= Investment Return and Income Taxes	$ 59,601,367		$ -		$ 59,601,367	To Worksheet 1A, line 14

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Western Massachusetts Electric Company (WMECO)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Investment Return and Income Taxes - 50bp

Line	(A)	(B) CAPITALIZATION (B) (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 578,162,814	50.45%		0.00%		
2	PREFERRED STOCK		0.00%		0.00%	0.00%	
3	COMMON EQUITY	$ 578,162,814	50.45%	0.50%	0.25%	0.25%	
4	TOTAL INVESTMENT RETURN	$ 1,156,325,628	100.90%		0.25%	0.25%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.0025

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit (W/S 1B) + Eq. AFUDC of Deprec. Exp. (Att. I)) / PTF Inv. Base (W/S 1B) x Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

6 = (0.0025 +(0 + 0) / 557,323,339) x 0.35)
7 (1 - 0.35)

8 = 0.001346

(c) State Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate / (1 - State Income Tax Rate)

9 = (0.0025 +(0 + 0) / 557,323,339) + 0.001346)* 0.08
10 (1 - 0.08)

11 = 0.000334

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.004180

Line		**Total PTF**
13	INVESTMENT BASE	$ 557,323,339
14	x Cost of Capital Rate	0.0041800
15	= Investment Return and Income Taxes	$ 2,329,612

Notes:
(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-224, Schedule 1, Page 2 of 4, Line 14
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Western Massachusetts Electric Company (WMECO)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Worksheet 3C

					Pre-1997 PTF		Post-1996 PTF			
		(1)	(2)	(3)	(4)	(5) = (3)*(4)	(6)	(7) = (3)*(6)		
			Wage/Plant		PTF		PTF	Post-96		
			Allocation		Allocation	PTF	Allocation	PTF		
LN.		Transmission	Factors (a)	Transmission	Factor (b)	Allocated	Factor (b)	Allocated	Reference	Notes
	Transmission Plant									
1	Transmission Plant					53,145,202		717,553,491	Attachment A2	(1)
2	General Plant	18,793,854		18,793,854	6.1211%	1,150,391	82.6455%	15,532,275	FF1 page 204 ln. 99, footnote	(1)
3	Total (line 1+2)	18,793,854		18,793,854		54,295,593		733,085,766		(1)
										(1)
4	Transmission Plant Held for Future Use	0		0	6.1211%	0	82.6455%	0	FF1 page 214 ln. 13	(1)
	Transmission Accumulated Depreciation									
5	Transmission Accum. Depreciation	54,279,720		54,279,720	6.1211%	3,322,516	82.6455%	44,859,746	FF1 page 219 ln. 25	(1)
6	General Plant Accum. Depreciation	4,371,591		4,371,591	6.1211%	267,589	82.6455%	3,612,923	FF1 page 219 ln. 28, footnote	(1)
7	Total (line 5+6)	58,651,311		58,651,311		3,590,105		48,472,669		(1)
	Transmission Accumulated Deferred Taxes									
8	Accumulated Deferred Taxes (281-283)	(225,957,746)		(225,957,746)	6.1211%	(13,831,100)	82.6455%	(186,743,909)	FF1 page 274 ln. 9 & 276 ln. 19, footnotes	(1)
9	Accumulated Deferred Taxes (190)	5,663,481 (c)		5,663,481	6.1211%	346,667	82.6455%	4,680,612	(c)	(1)
10	Total (line 8+9)	(220,294,265)		(220,294,265)		(13,484,433)		(182,063,297)		(1)
11	Transmission loss on Reacquired Debt	331,119		331,119	6.1211%	20,268	82.6455%	273,655	FF1 page 110 ln. 81, footnote	(1)
	Other Regulatory Assets									
12	Unamortized Balance of Transmission Merger-Related Costs	3,886,419		3,886,419	6.1211%	237,892	0.826455	3,211,950	**Exhibit No. ES-220, Page 4 of 8, Line 3(B)**	(2)
13	FAS 106	22,693		22,693	6.1211%	1,389	82.6455%	18,755	FF1 page 232.1 ln. 1, footnote	(1)
14	FAS 109	9,336,822		9,336,822	6.1211%	571,516	82.6455%	7,716,463	FF1 page 232 ln. 9, footnote	(1)
15	Other Regulatory Liabilities (254.DK)	(65,339)		(65,339)	6.1211%	(3,999)	82.6455%	(54,000)	FF1 page 278 ln. 5, footnote	(1)
16	Total (line 12+13+14)	13,180,595		13,180,595		806,798		10,893,168		(2)
17	Transmission Prepayments	1,023,867		1,023,867	6.1211%	62,672	82.6455%	846,180	FF1 page 110 ln. 57, footnote	(1)
18	Transmission Materials and Supplies	3,143,646		3,143,646	6.1211%	192,426	82.6455%	2,598,082	FF1 page 227 ln. 8	(1)
	Cash Working Capital									
19	Operation & Maintenance Expense					389,810		5,263,108	W/S 4C, Line 16	(1)
20	Administrative & General Expense					611,174		8,251,915	W/S 4C, Line 19	(3)
21	Transmission Support Expense					357,869			W/S 7	(1)
22	Subtotal (line 19+20+21)					1,358,853		13,515,023		(3)
23						0.125		0.125	x 45 / 360	(1)
24	Total (line 22 * line 23)					169,857		1,689,378		(3)

(a) All items are specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries and Plant Allocation Factors are not used (column 2).
(b) W/S 5A & 5B
(c)

Account 190	5,663,481	FF1 page 234 ln. 18, footnote	
Less Reserve for Disputed Transactions	-	FF1 page 234 ln. 18, footnote	(1)
Total Account 190	5,663,481		(1)

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Proposed revisions reflect the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset
(3) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Western Massachusetts Electric Company (WMECO)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Worksheet 4C

					Pre-1997 PTF		Post-1996 PTF			
LN.		(1) Transmission	(2) Wage/Plant Allocation Factors (a)	(3) Transmission	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	(6) PTF Allocation Factor (b)	(7) = (3)*(6) Post-96 PTF Allocated	Reference	Notes
	Depreciation Expense									
1	Transmission Depreciation	15,972,687		15,972,687	6.1211%	977,704	82.6455%	13,200,707	FF1 page 336 ln. 7	(1)
2	General Depreciation	789,658		789,658	6.1211%	48,336	82.6455%	652,617	FF1 page 336 ln. 10, footnote	(1)
3	Total (line 1+2)	16,762,345		16,762,345		1,026,040		13,853,324		(1)
4	Amortization of Loss on Reacquired Debt	49,668		49,668	6.1211%	3,040	82.6455%	41,048	FF1 page 114, ln. 64, footnote	(1)
5	Amortization of Investment Tax Credits	35,604		35,604	6.1211%	2,179	82.6455%	29,425	FF1 page 266 ln. 8(f), footnote	(1)
	Property Taxes									
6	Transmission Property Taxes	18,717,332		18,717,332	6.1211%	1,145,707	82.6455%	15,469,033	FF1 page 262 ln. 32i, footnote	(1)
7	General Property Taxes (c)				6.1211%	-	82.6455%	-		(1)
8	Total (line 6+7)	18,717,332		18,717,332		1,145,707		15,469,033		(1)
	Transmission Operation and Maintenance									
9	Operation and Maintenance	20,725,279		20,725,279	6.1211%	1,268,615	82.6455%	17,128,510	FF1 page 321 ln. 112	(1)
10	Transmission of Electricity by Others - #565	13,174,678		13,174,678	6.1211%	806,435	82.6455%	10,888,279	FF1 page 321 ln. 96	(1)
11	Account 561.1	12,368		12,368	6.1211%	757	82.6455%	10,222	FF1 page 321 ln. 85	(1)
12	Account 561.2	50,569		50,569	6.1211%	3,095	82.6455%	41,793	FF1 page 321 ln. 86	(1)
13	Account 561.3	13,262		13,262	6.1211%	812	82.6455%	10,960	FF1 page 321 ln. 87	(1)
14	Account 561.4	1,106,108		1,106,108	6.1211%	67,706	82.6455%	914,148	FF1 page 321 ln. 88	(1)
15	**Station Expenses & Rents	-			6.1211%	-	82.6455%	-	FF1 page 321 ln. 93 + ln. 98	(1)
16	O&M less lines 10 thru 15	6,368,294		6,368,294		389,810		5,263,108		(1)
	Transmission Administrative and General									
17	Administrative and General	8,041,502		8,041,502	6.1211%	492,228	82.6455%	6,645,940	FF1 page 320 ln. 197, footnote	(1)
18	Transmission Merger-Related Costs	1,943,209		1,943,209	6.1211%	118,946	82.6455%	1,605,975	**Exhibit No. ES-220, Page 4 of 8, Line 2(B)**	(2)
19	Total (line 17 + 18)					611,174		8,251,915		(2)
20	*Payroll Tax Expense*	18,291		18,291	6.1211%	1,120	82.6455%	15,117		(1)
	Federal Unemployment	283							FF1 page 262 ln. 3i, footnote	(1)
	FICA	13,202							FF1 page 262 ln. 5i, footnote	(1)
	Medicare	3,757							FF1 page 262 ln. 9i, footnote	(1)
	CT Unemployment	852							FF1 page 262 ln. 13i, footnote	(1)
	DC Unemployment	1							FF1 page 262.1 ln. 6i, footnote	(1)
	FL Unemployment	-							FF1 page 262.1 ln. 10i, footnote	(1)
	GA Unemployment	-							FF1 page 262.1 ln. 14i footnote	(1)
	MA Unemployment	69							FF1 page 262 ln. 22i, footnote	(1)
	MA Universal Health	19							FF1 page 262 ln. 27i, footnote	(1)
	MI Unemployment	-							FF1 page 262.1 ln. 14i footnote	(1)
	NH Unemployment	108							FF1 page 262 ln. 37i, footnote	(1)
	NJ Unemployment	-							FF1 page 262 footnote	(1)
	NY Unemployment	-							FF1 page 262.1, footnote	(1)
	Total	18,291	To Line 19							(1)

** To the extent that PTF Support Payments are reflected in worksheet 7 they will be excluded from this calculation.
(a) All items are specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries and Plant Allocation Factors are not used (column 2).
(b) W/S 5A & 5B
(c) Transmission related general property taxes are included in the Transmission Property tax number footnoted in the FF1.

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Exhibit No. ES-221
Schedule 4

CL&P's, PSNH's and WMECO's PTF Revenue Requirements under the Changed Rates for 2017

Eversource Energy Service Company

CL&P, PSNH and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For the Calendar Year 2017

Line	(A) Description	(B) Reference	(C) CL&P		(D) PSNH		(E) WMECO		(F)=(C)+(D)+(E) Total	
1	2014 Actual PTF Revenue Requirements		$ 461,417,471	(1)	$ 109,497,194	(2)	$ 111,979,403	(3)	$ 682,894,068	
2	Estimated 2015 PTF Plant Additions	(4)	$ 276,000,000		$ 114,000,000		$ 87,000,000		$ 477,000,000	
3	Carrying Charge Factor (CCF)	Exhibit No. ES-221, Schedule 2, Page 3 of 20, Note (3)	15.25%		16.55%		14.00%			
4	2015 Incremental Estimated PTF Revenue Requirements	Line 2 x 3	42,090,000		18,867,000		12,180,000		$ 73,137,000	
5	2015 Incremental Estimated PTF CWIP Rev. Req.	(4)	$ (19,400,000)		$ -		$ -		$ (19,400,000)	
6	Total Estimated PTF Revenue Requirement for 2015	Line 1 + 4 + 5	$ 484,107,471		$ 128,364,194		$ 124,159,403		$ 736,631,068	
7	Estimated 2016 PTF Plant Additions	(4)	$ 68,000,000		$ 117,000,000		$ 88,000,000		$ 273,000,000	
8	Carrying Charge Factor (CCF)	Line 3	15.25%		16.55%		14.00%			
9	2016 Incremental Estimated PTF Revenue Requirements	Line 7 x 8	10,370,000		19,363,500		12,320,000		$ 42,053,500	
10	Total Estimated PTF Revenue Requirement for 2016	Line 6 + 9	$ 494,477,471		$ 147,727,694		$ 136,479,403		$ 778,684,568	(5)

Notes:

(1) Exhibit No. ES-221: Schedule 4, Page 2 of 20, LN. 29(B) + Schedule 3, Page 3 of 20, LN. 29(B) + Schedule 3, Page 4 of 20, LN. 5(B) + Schedule 3, Page 5 of 20, LN. 9(B)
(2) Exhibit No. ES-221: Schedule 4, Page 2 of 20, LN. 29(C) + Schedule 3, Page 3 of 20, LN. 29(C) + Schedule 3, Page 4 of 20, LN. 5(C)
(3) Exhibit No. ES-221: Schedule 4, Page 2 of 20, LN. 29(D) + Schedule 3, Page 3 of 20, LN. 29(D) + Schedule 3, Page 4 of 20, LN. 5(D) + Schedule 3, Page 5 of 20, LN. 9(C)
(4) Based on Eversource's Forecast
(5) The revenue requirements calculations for the calendar year 2016 (including any forecast for 2016) are used as an estimate for the revenue requirements for 2017, which are used to calculate the revenue impact of the proposed cost recovery.

CL&P, PSNH and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Pre-1997

LN.		(A)	Attachment F Reference Section:	(B) CL&P	(C) PSNH	(D) WMECO	(E)=(B)+(C)+(D) Total	(F) Reference	(G) Notes
	I.	INVESTMENT BASE							
1		Transmission Plant	(A)(1)(a)	358,812,326	88,564,672	53,145,202	500,522,200	W/S 3A,3B,3C line 1	(1)
2		General Plant	(A)(1)(b)	12,027,048	7,336,167	1,150,391	20,513,606	W/S 3A,3B,3C line 2	(1)
3		Plant Held For Future Use	(A)(1)(c)	84,157	1,138,376	0	1,222,533	W/S 3A,3B,3C line 4	(1)
4		Total Plant (Lines 1+2+3)		370,923,531	97,039,215	54,295,593	522,258,339		(1)
5		Accumulated Depreciation	(A)(1)(d)	73,042,167	17,223,185	3,590,105	93,855,457	W/S 3A,3B,3C line 7	(1)
6		Accumulated Deferred Income Taxes	(A)(1)(e)	49,105,827	16,884,906	13,484,433	79,475,166	W/S 3A,3B,3C line 10	(1)
7		Loss On Reacquired Debt	(A)(1)(f)	623,759	245,415	20,268	889,442	W/S 3A,3B,3C line 11	(1)
8		Other Regulatory Assets	(A)(1)(g)	3,102,497	1,236,099	687,852	5,026,448	W/S 3A,3B,3C line 16	(2)
9		Net Investment (Line 4-5-6+7+8)		252,501,793	64,412,638	37,929,175	354,843,606		(2)
10		Prepayments	(A)(1)(h)	1,885,610	662,602	62,672	2,610,884	W/S 3A,3B,3C line 17	(1)
11		Materials & Supplies	(A)(1)(i)	4,547,780	1,261,158	192,426	6,001,364	W/S 3A,3B,3C line 18	(1)
12		Cash Working Capital	(A)(1)(j)	1,183,771	404,847	169,857	1,758,475	W/S 3A,3B,3C line 24	(2)
13		Total Investment Base (Line 9+10+11+12)		260,118,954	66,741,245	38,354,130	365,214,329		(2)
	II.	REVENUE REQUIREMENTS							
14		Investment Return and Income Taxes	(A)	32,339,029	7,950,751	4,405,854	44,695,634	W/S 2A,2B,2C, line 15	(2)
15		Depreciation Expense	(B)	8,594,771	1,919,255	1,026,040	11,540,066	W/S 4A,4B,4C line 3	(1)
16		Amortization of Loss on Reacquired Debt	(C)	68,393	30,531	3,040	101,964	W/S 4A,4B,4C line 4	(1)
17		Investment Tax Credit	(D)	(49,341)	(600)	(2,179)	(52,120)	W/S 4A,4B,4C line 5	(1)
18		Property Tax Expense	(E)	5,226,750	2,236,785	1,145,707	8,609,242	W/S 4A,4B,4C line 8	(1)
19		Payroll Tax Expense	(F)	37,155	(505)	1,120	37,770	W/S 4A,4B,4C line 20	(1)
20		Operation & Maintenance Expense	(G)	4,360,357	1,271,570	389,810	6,021,737	W/S 4A,4B,4C line 16	(1)
21		Administrative & General Expense	(H)	5,109,811	1,462,936	611,174	7,183,921	W/S 4A,4B,4C line 19	(2)
22		Transmission Related Integrated Facilities Charge	(I)	-	-	-	-	N/A	(1)
23		Transmission Support Revenue	(J)	(2,917,925)	(376,198)	-	(3,294,123)	W/S 7	(1)
24		Transmission Support Expense	(K)	1,625,568	880,469	357,869	2,863,906	W/S 7	(1)
25		Transmission Related Expense from Generators	(L)	-	-	-	-	N/A	(1)
26		Transmission Related Taxes and Fees Charge	(M)	1,135,268	19,553	1,263	1,156,084	Attachment B, line 14	(1)
27		Revenue for ST Trans. Service Under the OATT	(N)	(68,394)	(16,040)	(8,880)	(93,314)	Attachment C, line 9	(1)
28		Transmission Rents Received from Electric Property	(O)	(5,239,993)	(1,821,957)	(402,030)	(7,463,980)	Attachment C1, line 3	(1)
29		Total Revenue Requirements (Line 14 thru 28)		50,221,449	13,556,550	7,528,788	71,306,787		(2)

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.

(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

CL&P, PSNH and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Post-1996
Worksheet 1B

LN.		(A)	Attachment F Reference Section:	(B) CL&P	(C) PSNH	(D) WMECO	(E)=(B)+(C)+(D) Total	(F) Reference	(G) Notes
	I.	INVESTMENT BASE							
1		Transmission Plant	(A)(1)(a)	2,415,403,244	568,289,707	717,553,491	3,701,246,442	W/S 3A,3B,3C line 1	(1)
2		General Plant	(A)(1)(b)	80,962,316	47,073,591	15,532,275	143,568,182	W/S 3A,3B,3C line 2	(1)
3		Plant Held For Future Use	(A)(1)(c)	566,521	7,304,557	-	7,871,078	W/S 3A,3B,3C line 4	(1)
4		Total Plant (Lines 1+2+3)		2,496,932,081	622,667,855	733,085,766	3,852,685,702		(1)
5		Accumulated Depreciation	(A)(1)(d)	491,696,956	110,515,089	48,472,669	650,684,714	W/S 3A,3B,3C line 7	(1)
6		Accumulated Deferred Income Taxes	(A)(1)(e)	330,565,024	108,344,471	182,063,297	620,972,792	W/S 3A,3B,3C line 10	(1)
7		Loss On Reacquired Debt	(A)(1)(f)	4,198,950	1,574,739	273,655	6,047,344	W/S 3A,3B,3C line 11	(1)
8		Other Regulatory Assets	(A)(1)(g)	20,885,044	7,931,610	9,287,193	38,103,847	W/S 3A,3B,3C line 16	(2)
9		Net Investment (Line 4-5-6+7+8)		1,699,754,095	413,314,644	512,110,648	2,625,179,387		(2)
10		Prepayments	(A)(1)(h)	12,693,335	4,251,680	846,180	17,791,195	W/S 3A,3B,3C line 17	(1)
11		Materials & Supplies	(A)(1)(i)	30,614,229	8,092,403	2,598,082	41,304,714	W/S 3A,3B,3C line 18	(1)
12		Cash Working Capital	(A)(1)(j)	7,968,775	2,193,295	1,689,378	11,851,448	W/S 3A,3B,3C line 24	(2)
13		Total Investment Base Excluding CWIP (Line 9+10+11+12)		1,751,030,434	427,852,022	517,244,288	2,696,126,744		(2)
14		NEEWS Construction Work In Progress	(A)(1)(l)	164,948,530		-	164,948,530	(a)	(1)
15		Total Investment Base Including CWIP (Line 13+14)		1,915,978,964	427,852,022	517,244,288	2,861,075,274		(2)
	II.	REVENUE REQUIREMENTS							
16		Investment Return and Income Taxes	(A)	217,607,556	50,969,156	59,417,403	327,994,115	W/S 2A,2B,2C, line 15	(2)
17		Investment Return and Income Taxes-CWIP		20,498,814	-	-	20,498,814	W/S 2A,2B,2C, line 15	(1)
18		Depreciation Expense	(B)	57,857,303	12,315,183	13,853,324	84,025,810	W/S 4A,4B,4C line 3	(1)
19		Amortization of Loss on Reacquired Debt	(C)	460,401	195,905	41,048	697,354	W/S 4A,4B,4C line 4	(1)
20		Investment Tax Credit	(D)	(332,148)	(3,850)	(29,425)	(365,423)	W/S 4A,4B,4C line 5	(1)
21		Property Tax Expense	(E)	35,184,843	14,352,660	15,469,033	65,006,536	W/S 4A,4B,4C line 8	(1)
22		Payroll Tax Expense	(F)	250,119	(3,240)	15,117	261,996	W/S 4A,4B,4C line 20	(1)
23		Operation & Maintenance Expense	(G)	29,352,552	8,159,213	5,263,108	42,774,873	W/S 4A,4B,4C line 16	(1)
24		Administrative & General Expense	(H)	34,397,650	9,387,146	8,251,915	52,036,711	W/S 4A,4B,4C line 19	(2)
25		Transmission Related Integrated Facilities Charge	(I)	-	-	-	-	N/A	(1)
26		Transmission Related Expense from Generators	(L)	-	-	-	-	N/A	(1)
27		Transmission Related Taxes and Fees Charge	(M)	7,642,269	125,466	17,047	7,784,782	Attachment B line 16	(1)
28		Revenue for ST Trans. Service Under the OATT	(N)	(460,565)	(102,948)	(119,820)	(683,333)	Attachment C line 10	(1)
29		Total Revenue Requirements (Line 16 thru 28)		402,458,794	95,394,691	102,178,750	600,032,235		(2)

(a) Reflects actual information per Eversource's accounting records

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

CL&P, PSNH and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Post-2003
Worksheet 1C

LN.	(A) I. INVESTMENT BASE	(B) CL&P	(C) PSNH	(D) WMECO	(E)=(B)+(C)+(D) TOTAL	(F) REFERENCE	(G) Notes
1	Transmission Plant	$ 1,535,579,816	$ 124,215,608	$ 12,384,353	$ 1,672,179,777	Attachment D, D2, D4	(1)
2	Accumulated Depreciation	$ 213,218,089	$ 18,074,549	$ 1,442,093	$ 232,734,731	Attachment D, D2, D4	(1)
3	Accumulated Deferred Income Taxes	$ 155,340,565	$ 15,930,789	$ 2,675,475	$ 173,946,829	Attachment D1, D3, D5	(1)
4	Net Investment (Line 1-2-3)	$ 1,167,021,162	$ 90,210,270	$ 8,266,785	$ 1,265,498,217		(1)
	II. INCREMENTAL RETURN						
5	Incremental Revenue Requirements	$ 6,906,431	$ 545,953	$ 47,005	$ 7,499,389	W/S 2A,2B,2C Post 2003	(1)

Note: ROE incentives approved in FERC Opinion No. 489. As a result of Opinion No. 531-B, these projects receive an ROE incentive of 67 bp.

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.

CL&P, PSNH and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
NEEWS
Worksheet 1E

LN.	(A) I. INVESTMENT BASE	(B) CL&P	(C) WMECO	(D) = (B) + (C) Total	(E) REFERENCE	(F) Notes
1	Transmission Plant	$ 200,288,632	$ 556,313,751	$ 756,602,383	Attachment F & F2	(1)
2	Accumulated Depreciation	$ 8,946,318	$ 22,283,705	$ 31,230,023	Attachment F & F2	(1)
3	Accumulated Deferred Income Taxes	$ 46,929,968	$ 142,742,742	$ 189,672,710	Attachment F1 & F3	(1)
4	Net Investment Excluding CWIP(Line 1-2-3)	$ 144,412,346	$ 391,287,304	$ 535,699,650		(1)
5	NEEWS Construction Work In Progress	$ 164,948,530	$ -	$ 164,948,530	Attachment F & F2	(1)
6	Net Investment Including CWIP(Line 4+5)	$ 309,360,876	$ 391,287,304	$ 700,648,180		(1)
	II. INCREMENTAL RETURN					
7	Incremental Revenue Requirements	$ 854,632	$ 2,224,860	$ 3,079,492	W/S 2A & 2C NEEWS	(1)
8	Incremental Revenue Requirements-CWIP	$ 976,165	$ -	$ 976,165	W/S 2A & 2C NEEWS	(1)
9	Total Incremental Revenue Requirements (line 7+8)	$ 1,830,797	$ 2,224,860	$ 4,055,657		(1)

Note: Incentives approved in FERC Docket No. ER08-1548. As a result of Opinion No. 531-B, this project receives ROE incentives of 67 bp.

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.

Connecticut Light & Power Company (CL&P)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Investment Return and Income Taxes - Pre 1997
Worksheet 2A

Line	(A)		(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$	2,579,060,322	45.78%	5.36%	2.45%		
2	PREFERRED STOCK	$	116,868,097	2.07%	4.80%	0.10%	0.10%	
3	COMMON EQUITY	$	2,938,441,767	52.15%	11.07%	5.77%	5.77%	
4	TOTAL INVESTMENT RETURN	$	5,634,370,186	100.00%		8.32%	5.87%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.0832

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit (W/S 1A) + Eq. AFUDC of Deprec. Exp. (Att. I)) / PTF Inv. Base (W/S 1A) x Federal Income Tax Rate)
(1 - Federal Income Tax Rate)

6 = 0.0587 +((49,341) + 269,748) / 260,118,954) x 0.35)
7 (1 - 0.35)

8 = 0.032064

(c) State Income Tax = R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate
(1 - State Income tax Rate)

9 = 0.0587 +((49,341) + 269,748) / 260,118,954) + 0.032064)* 0.09
10 (1 - 0.09)

11 = 0.009060

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.124324

Line			**Pre-1997 PTF**	
13	INVESTMENT BASE	$	260,118,954	From Worksheet 1A, line 13
14	x Cost of Capital Rate		0.124324	
15	= Investment Return and Income Taxes	$	32,339,029	To Worksheet 1A, line 14

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) The balance in "Total Inv. Base" is revised under the Changed Rates

Connecticut Light & Power Company (CL&P)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Investment Return and Income Taxes - Post 1996
Worksheet 2A

Line	(A)	(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 2,579,060,322	45.78%	5.36%	2.45%		
2	PREFERRED STOCK	$ 116,868,097	2.07%	4.80%	0.10%	0.10%	
3	COMMON EQUITY	$ 2,938,441,767	52.15%	11.07%	5.77%	5.77%	
4	TOTAL INVESTMENT RETURN	$ 5,634,370,186	100.00%		8.32%	5.87%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.0832

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit (W/S 1B) + Eq. AFUDC of Deprec. Exp. (Att. I)) / PTF Inv. Base (W/S 1B) x Federal Income Tax Rate)
(1 - Federal Income Tax Rate)

6 = 0.0587 +((332,148) + 1,815,862) / 1,915,978,964) x 0.35)
7 (1 - 0.35)

8 = 0.032025

(c) State Income Tax = R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate
(1 - State Income tax Rate)

9 = 0.0587 +((332,148) + 1,815,862) / 1,915,978,964) + 0.032025)* 0.09
10 (1 - 0.09)

11 = 0.009049

12 (a)+(b)+(c) Cost of Capital Rate = 0.124274

Line		Post - 1996 Total PTF	-	Post - 1996 PTF CWIP	=	Post -1996 PTF Excluding CWIP	
13	INVESTMENT BASE	$ 1,915,978,964		$ 164,948,530		$ 1,751,030,434	From Worksheet 1B, line 13, 14
14	x Cost of Capital Rate	0.124274		0.124274		0.124274	
15	= Investment Return and Income Taxes	$ 238,106,370		$ 20,498,814		$ 217,607,556	To Worksheet 1B, line 16

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) The balance in "Total Inv. Base" is revised under the Changed Rates

Connecticut Light & Power Company (CL&P)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Investment Return and Income Taxes - 50bp

Line	(A)	(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 2,579,060,322	45.78%		0.00%		
2	PREFERRED STOCK	$ 116,868,097	2.07%		0.00%	0.00%	
3	COMMON EQUITY	$ 2,938,441,767	52.15%	0.50%	0.26%	0.26%	
4	TOTAL INVESTMENT RETURN	$ 5,634,370,186	100.00%		0.26%	0.26%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.0026

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit (W/S 1B) + Eq. AFUDC of Deprec. Exp. (Att. I)) / PTF Inv. Base (W/S 1B) x Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

6 = 0.0026 +(0 + 0) / 2,176,097,918) x 0.35)
7 (1 - 0.35)

8 = 0.001400

(c) State Income Tax = R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate / (1 - State Income tax Rate)

9 = 0.0026 +(0 + 0) / 2,176,097,918) + 0.001400)* 0.09
10 (1 - 0.09)

11 = 0.000396

12 (a)+(b)+(c) Cost of Capital Rate = 0.004396

Line		Total PTF
13	INVESTMENT BASE	$ 2,176,097,918
14	x Cost of Capital Rate	0.004396
15	= Investment Return and Income Taxes	$ 9,566,126

Notes:
(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-224, Schedule 1, Page 3 of 4, Line 14
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Connecticut Light & Power Company (CL&P)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Worksheet 3A

					Pre-1997 PTF		Post-1996 PTF			
		(1)	(2)	(3)	(4)	(5) = (3)*(4)	(6)	(7) = (3)*(6)		
LN.		Transmission	Wage/Plant Allocation Factors (a)	Transmission	PTF Allocation Factor (b)	PTF Allocated	PTF Allocation Factor (b)	PTF Allocated	Reference	Notes
	Transmission Plant									
1	Transmission Plant					358,812,326		2,415,403,244	Attachment A (H1)	(1)
2	General Plant	104,400,554		104,400,554	11.5201%	12,027,048	77.5497%	80,962,316	FF1 page 204 ln. 99, footnote	(1)
3	Total (line 1+2)	104,400,554		104,400,554		370,839,374		2,496,365,560		(1)
										(1)
4	Transmission Plant Held for Future Use	730,526	(c)	730,526	11.5201%	84,157	77.5497%	566,521	(c)	(1)
	Transmission Accumulated Depreciation									
5	Transmission Accum. Depreciation	605,238,764		605,238,764	11.5201%	69,724,111	77.5497%	469,360,846	FF1 page 219 ln. 25	(1)
6	General Plant Accum. Depreciation	28,802,317		28,802,317	11.5201%	3,318,056	77.5497%	22,336,110	FF1 page 219 ln. 28, footnote	(1)
7	Total (line 5+6)	634,041,081		634,041,081		73,042,167		491,696,956	Schedule 2, Page 6,7,8	(1)
	Transmission Accumulated Deferred Taxes									
8	Accumulated Deferred Taxes (281 to 283)	(470,775,688)		(470,775,688)	11.5201%	(54,233,830)	77.5497%	(365,085,134)	FF1 page 274 ln. 9 & 276 ln. 19 fns	(1)
9	Accumulated Deferred Taxes (190)	44,513,531	(d)	44,513,531	11.5201%	5,128,003	77.5497%	34,520,110	(d)	(1)
10	Total (line 8+9)	(426,262,157)		(426,262,157)		(49,105,827)		(330,565,024)		(1)
11	Transmission loss on Reacquired Debt	5,414,528		5,414,528	11.5201%	623,759	77.5497%	4,198,950	FF1 page 110 ln. 81, footnote	(1)
	Other Regulatory Assets									
12	Unamortized Balance of Transmission Merger-Related Costs	7,153,326		7,153,326	11.5201%	824,070	77.5497%	5,547,383	**Exhibit No. ES-220, Page 1 of 8, Line 3(C)**	(2)
13	FAS 106	66,791		66,791	11.5201%	7,694	77.5497%	51,796	FF1 page 232 Ln. 27, footnote	(1)
14	FAS 109	23,019,567		23,019,567	11.5201%	2,651,877	77.5497%	17,851,605	FF1 page 232 ln. 7, footnote	(1)
15	Other Regulatory Liabilities (254.DK)	(3,308,510)		(3,308,510)	11.5201%	(381,144)	77.5497%	(2,565,740)	FF1 page 278 ln. 3, footnote	(1)
16	Total (line 12+13+14)	26,931,174		26,931,174		3,102,497		20,885,044		(2)
17	Transmission Prepayments (165)	16,368,000		16,368,000	11.5201%	1,885,610	77.5497%	12,693,335	FF1 page 110 ln. 57, footnote	(1)
18	Transmission Materials and Supplies	39,476,915		39,476,915	11.5201%	4,547,780	77.5497%	30,614,229	FF1 page 227 ln. 8	(1)
	Cash Working Capital									
19	Operation & Maintenance Expense					4,360,357		29,352,552	W/S 4A, Line 16	(1)
20	Administrative & General Expense					5,109,811		34,397,650	W/S 4A, Line 19	(3)
21	Transmission Support Expense					-		-	W/S 7	(1)
22	Subtotal (line 18+19+20)					9,470,168		63,750,202		(3)
23						0.125		0.125	x 45 / 360	(1)
24	Total (line 21 * line 22)					1,183,771		7,968,775		(3)

(a) All items are specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries and Plant Allocation Factors are not used (colum
(b) W/S 5A & 5B

(c)	Account 105	32,127,498	FF1 page 214 ln. 33	(1)
	Less Third Underground Conduit Duct	31,396,972	FF1 page 214 ln. 22	(1)
		730,526		(1)
(d)	Account 190	46,955,376	FF1 page 234 ln. 18, footnote	(1)
	Less Reserve for Disputed Transactions	2,441,845	FF1 page 234 ln. 18, footnote	(1)
	Total Account 190	44,513,531		(1)

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Proposed revisions reflect the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset
(3) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Connecticut Light & Power Company (CL&P)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Worksheet 4A

					PRE-97 PTF		POST-96 PTF			
		(1)	(2)	(3)	(4)	(5) = (3)*(4)	(6)	(7) = (3)*(6)		
LN.		Transmission	Wage/Plant Allocation Factors (a)	Transmission	PTF Allocation Factor (b)	PTF Allocated	PTF Allocation Factor (b)	Post-96 PTF Allocated	Reference	Notes
	Depreciation Expense									
1	Transmission Depreciation	69,626,166		69,626,166	11.5201%	8,021,004	77.5497%	53,994,883	FF1 page 336 ln. 7	(1)
2	General Depreciation	4,980,574		4,980,574	11.5201%	573,767	77.5497%	3,862,420	FF1 page 336 ln. 10, footnote	(1)
3	Total (line 1+2)	74,606,740		74,606,740		8,594,771		57,857,303		(1)
4	Amortization of Loss on Reacquired Debt	593,685		593,685	11.5201%	68,393	77.5497%	460,401	FF1 page 114 ln. 64, footnote	(1)
5	Amortization of Investment Tax Credits	428,304		428,304	11.5201%	49,341	77.5497%	332,148	FF1 page 266 ln. 8(f), footnote	(1)
	Property Taxes									
6	Transmission Property Taxes	45,370,701		45,370,701	11.5201%	5,226,750	77.5497%	35,184,843	FF1 page 262 ln. 25i, footnote	(1)
7	General Property Taxes (c)	-		-	11.5201%	-	77.5497%	-		(1)
8	Total (line 6+7)	45,370,701		45,370,701		5,226,750		35,184,843		(1)
	Transmission Operation and Maintenance									
9	Operation and Maintenance	77,432,007		77,432,007	11.5201%	8,920,245	77.5497%	60,048,289	FF1 page 321 ln. 112	(1)
10	Transmission of Electricity by Others - #565	21,727,966		21,727,966	11.5201%	2,503,083	77.5497%	16,849,972	FF1 page 321 ln. 96	(1)
11	Account 561.1	3,245,594		3,245,594	11.5201%	373,896	77.5497%	2,516,948	FF1 page 321 ln. 85	(1)
12	Account 561.2	5,212,556		5,212,556	11.5201%	600,492	77.5497%	4,042,322	FF1 page 321 ln. 86	(1)
13	Account 561.3	2,238,612		2,238,612	11.5201%	257,890	77.5497%	1,736,037	FF1 page 321 ln. 87	(1)
14	Account 561.4	7,157,291		7,157,291	11.5201%	824,527	77.5497%	5,550,458	FF1 page 321 ln. 88	(1)
15	**Station Expenses & Rents	-		-	11.5201%	-	77.5497%	-	FF1 page 321 ln. 93 + ln. 98	(1)
16	O&M less lines 10 thru 15	37,849,988		37,849,988		4,360,357		29,352,552		(1)
	Transmission Administrative and General									
17	Administrative and General	37,202,294		37,202,294	11.5201%	4,285,741	77.5497%	28,850,267	FF1 page 320 ln. 197 b, footnote	(1)
18	Transmission Merger-Related Costs	7,153,326		7,153,326	11.5201%	824,070	77.5497%	5,547,383	**Exhibit No. ES-220, Page 1 of 8, Line 2(C)**	(2)
19	Total (line 17 + 18)					5,109,811		34,397,650		(2)
20	*Payroll Tax Expense*	322,527		322,527	11.5201%	37,155	77.5497%	250,119		(1)
	Federal Unemployment	5,226							FF1 page 262 ln. 3i, footnote	(1)
	FICA	233,351							FF1 page 262 ln. 5i, footnote	(1)
	Medicare	65,613							FF1 page 262 ln. 9i, footnote	(1)
	CT Unemployment	16,786							FF1 page 262 ln. 15i, footnote	(1)
	DC Unemployment	11							FF1 page 262.1 ln. 14i, footnote	(1)
	FL Unemployment	1							FF1 page 262.1 ln. 18i, footnote	(1)
	GA Unemployment	-							FF1 page 262 footnote	(1)
	MA Unemployment	(285)							FF1 page 262 ln. 32i, footnote	(1)
	MA Universal Health	64							FF1 page 262 ln. 33i, footnote	(1)
	MI Unemployment	6							FF1 page 262.1 ln. 22i, footnote	(1)
	NH Unemployment	1,754							FF1 page 262.1 ln. 4i, footnote	(1)
	NJ Unemployment	-							FF1 page 262 footnote	(1)
	NY Unemployment	-							FF1 page 262.1 ln. 10i, footnote	(1)
	Total	322,527	To Line 18							(1)

** To the extent that PTF Support Payments are reflected in worksheet 7 they will be excluded from this calculation.
(a) All items are specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries and Plant Allocation Factors are not used (column 2).
(b) W/S 5A & 5B
(c) Transmission related general property taxes are included in the Transmission Property tax number footnoted in the FF1.

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Public Service Company of New Hampshire (PSNH)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Investment Return and Income Taxes - Pre 1997
Worksheet 2B

	(A)	(B)	(C)	(D)	(E)	(F)	(G)
Line		CAPITALIZATION 12/31/2014 (Attachment H)	CAPITALIZATION RATIOS	COST OF CAPITAL	WEIGHTED COST OF CAPITAL	EQUITY PORTION	
1	LONG-TERM DEBT	$ 1,070,020,120	46.56%	4.15%	1.93%		
2	PREFERRED STOCK	$ -	0.00%	0.00%	0.00%	0.00%	
3	COMMON EQUITY	$ 1,228,095,985	53.44%	11.07%	5.92%	5.92%	
4	TOTAL INVESTMENT RETURN	$ 2,298,116,105	100.00%		7.85%	5.92%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.0785

(b) Federal Income Tax =((R.O.E. + (PTF Inv. (Tax Credit (W/S 1A) + Eq. AFUDC of Deprec. Exp. (Att. I)) / PTF Inv. Base (W/S 1A) x Federal Income Tax Rate)
(1 - Federal Income Tax Rate)

6 =(0.0592 +((600) + 29,005) / 66,741,245) x 0.35)
7 (1 - 0.35)

8 = 0.032106

(c) State Income Tax =(R.O.E. + +(PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate
(1 - State Income Tax Rate)

9 =(0.0592 +((600) + 29,005) / 66,741,245) + 0.032106)* 0.085
10 (1 - 0.085)

11 = 0.008522

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.119128

Line		**Pre-1997 PTF**	
13	INVESTMENT BASE	$ 66,741,245	From Worksheet 1A, line 13
14	x Cost of Capital Rate	0.1191280	
15	= Investment Return and Income Taxes	$ 7,950,751	To Worksheet 1A, line 14

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) The balance in "Total Inv. Base" is revised under the Changed Rates

Public Service Company of New Hampshire (PSNH)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Investment Return and Income Taxes - Post 1996
Worksheet 2B

Line	(A)	(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 1,070,020,120	46.56%	4.15%	1.93%		
2	PREFERRED STOCK	$ -	0.00%	0.00%	0.00%	0.00%	
3	COMMON EQUITY	$ 1,228,095,985	53.44%	11.07%	5.92%	5.92%	
4	TOTAL INVESTMENT RETURN	$ 2,298,116,105	100.00%		7.85%	5.92%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.0785

(b) Federal Income Tax = ((R.O.E. + (PTF Inv. (Tax Credit (W/S 1B) + Eq. AFUDC of Deprec. Exp. (Att. I)) / PTF Inv. Base (W/S 1A) x Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

6 = (0.0592 +((3,850) + 186,109) / 427,852,022) x 0.35)
7 (1 - 0.35)

8 = 0.032106

(c) State Income Tax = (R.O.E. + +(PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate / (1 - State Income Tax Rate)

9 = (0.0592 +((3,850) + 186,109) / 427,852,022) + 0.032106)* 0.085
10 (1 - 0.085)

11 = 0.008522

12 (a)+(b)+(c) Cost of Capital Rate = 0.119128

Line		**Post - 1996Total PTF**	
13	INVESTMENT BASE	$ 427,852,022	From Worksheet 1A, line 13
14	x Cost of Capital Rate	0.119128	
15	= Investment Return and Income Taxes	$ 50,969,156	To Worksheet 1B, line 16

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) The balance in "Total Inv. Base" is revised under the Changed Rates

Public Service Company of New Hampshire (PSNH)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Investment Return and Income Taxes - 50bp

Line	(A)	(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 1,070,020,120	46.56%		0.00%		
2	PREFERRED STOCK	$ -	0.00%		0.00%	0.00%	
3	COMMON EQUITY	$ 1,228,095,985	53.44%	0.50%	0.27%	0.27%	
4	TOTAL INVESTMENT RETURN	$ 2,298,116,105	100.00%		0.27%	0.27%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.0027

(b) Federal Income Tax = ((R.O.E. + (PTF Inv. (Tax Credit (W/S 1B) + Eq. AFUDC of Deprec. Exp. (Att. I)) / PTF Inv. Base (W/S 1A) x Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

6 = (0.0027 +(0 + 0) / 494,593,267) x 0.35)
7 (1 - 0.35)

8 = 0.001454

(c) State Income Tax = (R.O.E. + +(PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate / (1 - State Income Tax Rate)

9 = (0.0027 +(0 + 0) / 494,593,267) + 0.001454)* 0.085
10 (1 - 0.085)

11 = 0.000386

12 (a)+(b)+(c) Cost of Capital Rate = 0.004540

Line		Total PTF
13	INVESTMENT BASE	$ 494,593,267
14	x Cost of Capital Rate	0.004540
15	= Investment Return and Income Taxes	$ 2,245,453

Notes:

(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-224, Schedule 1, Page 3 of 4, Line 14
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Public Service Company of New Hampshire (PSNH)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Worksheet 3B

					Pre-1997 PTF		Post-1996 PTF			
		(1)	(2) Wage/Plant Allocation Factors (a)	(3)	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	(6) PTF Allocation Factor (b)	(7) = (3)*(6) Post-96 PTF Allocated		
LN.		Transmission		Transmission					Reference	Notes
	Transmission Plant									
1	Transmission Plant					88,564,672		568,289,707	Attachment A1	(1)
2	General Plant	59,322,426		59,322,426	12.3666%	7,336,167	79.3521%	47,073,591	FF1 page 204 ln. 99, footnote	(1)
3	Total (line 1+2)	59,322,426		59,322,426		95,900,839		615,363,298		(1)
										(1)
4	Transmission Plant Held for Future Use	9,205,247		9,205,247	12.3666%	1,138,376	79.3521%	7,304,557	FF1 page 214 ln. 35	(1)
	Transmission Accumulated Depreciation									
5	Transmission Accum. Depreciation	123,132,357		123,132,357	12.3666%	15,227,286	79.3521%	97,708,111	FF1 page 219 ln. 25	(1)
6	General Plant Accum. Depreciation	16,139,432		16,139,432	12.3666%	1,995,899	79.3521%	12,806,978	FF1 page 219 ln. 28, footnote	(1)
7	Total (line 5+6)	139,271,789		139,271,789		17,223,185		110,515,089		(1)
	Transmission Accumulated Deferred Taxes									
8	Accumulated Deferred Taxes (281-283)	(145,475,861)		(145,475,861)	12.3666%	(17,990,418)	79.3521%	(115,438,151)	FF1 page 274 ln. 9 & 276 ln. 19 fns	(1)
9	Accumulated Deferred Taxes (190)	8,939,499 (c)		8,939,499	12.3666%	1,105,512	79.3521%	7,093,680	(c)	(1)
10	Total (line 8+9)	(136,536,362)		(136,536,362)		(16,884,906)		(108,344,471)		(1)
				-						
11	Transmission loss on Reacquired Debt	1,984,496		1,984,496	12.3666%	245,415	79.3521%	1,574,739	FF1 page 110 ln. 81, footnote	(1)
	Other Regulatory Assets									
12	Unamortized Balance of Transmission Merger-Related Costs	1,481,622		1,481,622	0.123666	183,226	0.793521	1,175,698	**Exhibit No. ES-220, Page 3 of 8, Line 3(C)**	(2)
13	FAS 106	350,591		350,591	12.3666%	43,356	79.3521%	278,201	FF1 page 232.1 ln. 15, footnote	(1)
14	FAS 109	8,171,016		8,171,016	12.3666%	1,010,477	79.3521%	6,483,873	FF1 page 232 ln. 1, footnote	(1)
15	Other Regulatory Liabilities (254.DK)	(7,765)		(7,765)	12.3666%	(960)	79.3521%	(6,162)	FF1 page 278 ln. 1, footnote	(1)
16	Total (line 12+13+14)	9,995,464		9,995,464		1,236,099		7,931,610		(2)
17	Transmission Prepayments	5,357,993		5,357,993	12.3666%	662,602	79.3521%	4,251,680	FF1 page 110 ln. 57, footnote	(1)
18	Transmission Materials and Supplies	10,198,096		10,198,096	12.3666%	1,261,158	79.3521%	8,092,403	FF1 page 227 ln. 8	(1)
	Cash Working Capital									
19	Operation & Maintenance Expense					1,271,570		8,159,213	W/S 4B, Line 16	(1)
20	Administrative & General Expense					1,462,936		9,387,146	W/S 4B, Line 19	(3)
21	Transmission Support Expense					504,271		-	W/S 7	(1)
22	Subtotal (line 18+19+20)					3,238,777		17,546,359		(3)
23						0.125		0.125	x 45 / 360	(1)
24	Total (line 21 * line 22)					404,847		2,193,295		(3)

(a) All items are specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries and Plant Allocation Factors are not used (column 2).
(b) W/S 5A & 5B
(c)

Account 190	8,939,499	FF1 page 234 ln. 18, footnote	(1)
Less Reserve for Disputed Transactions	-	FF1 page 234 ln. 18, footnote	(1)
Total Account 190	8,939,499		(1)

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Proposed revisions reflect the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset
(3) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expense

Public Service Company of New Hampshire (PSNH)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Worksheet 4B

LN.		(1) Transmission	(2) Wage/Plant Allocation Factors (a)	(3) Transmission	Pre-1997 PTF (4) PTF Allocation Factor (b)	Pre-1997 PTF (5) = (3)*(4) PTF Allocated	Post-1996 PTF (6) PTF Allocation Factor (b)	Post-1996 PTF (7) = (3)*(6) Post-96 PTF Allocated	Reference	Notes
	Depreciation Expense									
1	Transmission Depreciation	12,792,512		12,792,512	12.3666%	1,581,999	79.3521%	10,151,127	FF 1 page 336 ln. 7	(1)
2	General Depreciation	2,727,156		2,727,156	12.3666%	337,256	79.3521%	2,164,056	FF1 page 336 ln. 10, footnote	(1)
3	Total (line 1+2)	15,519,668		15,519,668		1,919,255		12,315,183		(1)
4	Amortization of Loss on Reacquired Debt	246,881		246,881	12.3666%	30,531	79.3521%	195,905	FF1 page 114 ln. 64, footnote	(1)
5	Amortization of Investment Tax Credits	4,852		4,852	12.3666%	600	79.3521%	3,850	FF1 page 266 ln. 8(f), footnote	(1)
	Property Taxes									
6	Transmission Property Taxes	18,087,310		18,087,310	12.3666%	2,236,785	79.3521%	14,352,660	FF1 page 262 ln. 23i + ln. 30i +	(1)
7	General Property Taxes (c)	-		-	12.3666%	-	79.3521%	-	page 262.1 ln. 2i, footnote	(1)
8	Total (line 6+7)	18,087,310		18,087,310		2,236,785		14,352,660		(1)
	Transmission Operation and Maintenance									
9	Operation and Maintenance	51,082,852		51,082,852	12.3666%	6,317,212	79.3521%	40,535,316	FF1 page 321 ln. 112	(1)
10	Transmission of Electricity by Others - #565	37,174,569		37,174,569	12.3666%	4,597,230	79.3521%	29,498,801	FF1 page 321 ln. 96	(1)
11	Account 561.1	653,575		653,575	12.3666%	80,825	79.3521%	518,625	FF1 page 321 ln. 85	(1)
12	Account 561.2	474,690		474,690	12.3666%	58,703	79.3521%	376,676	FF1 page 321 ln. 86	(1)
13	Account 561.3	36,962		36,962	12.3666%	4,571	79.3521%	29,330	FF1 page 321 ln. 87	(1)
14	Account 561.4	2,460,768		2,460,768	12.3666%	304,313	79.3521%	1,952,671	FF1 page 321 ln. 88	(1)
15	**Station Expenses & Rents	-		-	12.3666%	-	79.3521%	-	FF1 page 321 ln. 93 + ln. 98	(1)
16	O&M less lines 10 thru 15	10,282,288		10,282,288		1,271,570		8,159,213		(1)
	Transmission Administrative and General									
17	Administrative and General	10,348,117		10,348,117	12.3666%	1,279,710	79.3521%	8,211,448	FF1 page 320 ln. 197 b, footnote	(1)
18	Transmission Merger-Related Costs	1,481,622		1,481,622	12.3666%	183,226	79.3521%	1,175,698	**Exhibit No. ES-220, Page 3 of 8, Line 2(C)**	(2)
19	Total (line 17 + 18)					1,462,936		9,387,146		(2)
20	*Payroll Tax Expense*	(4,083)		(4,083)	12.3666%	(505)	79.3521%	(3,240)		(1)
	Federal Unemployment	(51)							FF1 page 262 ln. 2i, footnote	(1)
	FICA	(3,062)							FF1 page 262 ln. 4i, footnote	(1)
	Medicare	(816)							FF1 page 262 ln. 7i, footnote	(1)
	CT Unemployment	(128)							FF1 page 262.1 ln. 7i, footnote	(1)
	DC Unemployment	0							FF1 page 262 ln. 26i, footnote	(1)
	FL Unemployment	0							FF1 page 262.1 ln. 27i, footnote	(1)
	GA Unemployment	0							FF1 page 262.1, footnote	(1)
	MA Unemployment	2							FF1 page 262.1 ln. 15i, footnote	(1)
	MA Universal Health	(1)							FF1 page 262.1 ln. 16i, footnote	(1)
	MI Unemployment	0							FF1 page 262.1 ln. 31i, footnote	(1)
	NH Unemployment	(27)							FF1 page 262 ln. 14i, footnote	(1)
	NJ Unemployment	0							FF1 page 262, footnote	(1)
	NY Unemployment	0							FF1 page 262 footnote	(1)
	Total	(4,083)	To Line 19							(1)

** To the extent that PTF Support Payments are reflected in worksheet 7 they will be excluded from this calculation.
(a) All items are specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries and Plant Allocation Factors are not used (column 2).
(b) W/S 5A & 5B
(c) Transmission related general property taxes are included in the Transmission Property tax number footnoted in the FF1.

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-00
(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expense

Western Massachusetts Electric Company (WMECO)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Investment Return and Income Taxes - Pre 1997
Worksheet 2C

Line	(A)	(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 567,833,428	49.55%	4.31%	2.14%		
2	PREFERRED STOCK	$ -	0.00%	0.00%	0.00%	0.00%	
3	COMMON EQUITY	$ 578,162,814	50.45%	11.07%	5.58%	5.58%	
4	TOTAL INVESTMENT RETURN	$ 1,145,996,242	100.00%		7.72%	5.58%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.0772

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit (W/S 1A) + Eq. AFUDC of Deprec. Exp. (Att. I)) / PTF Inv. Base (W/S 1A) x Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

6 = (0.0558 +((2,179) + 11,396) / 38,354,130) x 0.35)
7 (1 - 0.35)

8 = 0.030176

(c) State Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate / (1 - State Income Tax Rate)

9 = (0.0558 +((2,179) + 11,396) / 38,354,130) + 0.030176)* 0.08
10 (1 - 0.08)

11 = 0.007497

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.114873

Line		**Pre-1997 PTF**	
13	INVESTMENT BASE	$ 38,354,130	From Worksheet 1A, line 13
14	x Cost of Capital Rate	0.114873	
15	= Investment Return and Income Taxes	$ 4,405,854	To Worksheet 1A, line 14

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) The balance in "Total Inv. Base" is revised under the Changed Rates

Western Massachusetts Electric Company (WMECO)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014

Investment Return and Income Taxes - Post 1996

Worksheet 2C

Line	(A)	(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 567,833,428	49.55%	4.31%	2.14%		
2	PREFERRED STOCK	$ -	0.00%	0.00%	0.00%	0.00%	
3	COMMON EQUITY	$ 578,162,814	50.45%	11.07%	5.58%	5.58%	
4	TOTAL INVESTMENT RETURN	$ 1,145,996,242	100.00%		7.72%	5.58%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.0772

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit (W/S 1B) + Eq. AFUDC of Deprec. Exp. (Att. I)) / PTF Inv. Base (W/S 1B) x Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

6 = (0.0558 +((29,425) + 153,859) / 517,244,288) x 0.35)
7 (1 - 0.35)

8 = 0.030176

(c) State Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate / (1 - State Income Tax Rate)

9 = (0.0558 +((29,425) + 153,859) / 517,244,288) + 0.030176)* 0.08
10 (1 - 0.08)

11 = 0.007497

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.114873

Line		**Post - 1996 Total PTF**	-	**Post - 1996 PTF CWIP**	=	**Post -1996 PTF Excluding CWIP**	
13	INVESTMENT BASE	$ 517,244,288		$ -		$ 517,244,288	From Worksheet 1B, line 13, 14
14	x Cost of Capital Rate	0.1148730		0.1148730		0.1148730	
15	= Investment Return and Income Taxes	$ 59,417,403		$ -		$ 59,417,403	To Worksheet 1A, line 14

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) The balance in "Total Inv. Base" is revised under the Changed Rates

Western Massachusetts Electric Company (WMECO)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014

Investment Return and Income Taxes - 50bp

Line	(A)	(B) CAPITALIZATION (B) (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 578,162,814	50.45%		0.00%		
2	PREFERRED STOCK		0.00%		0.00%	0.00%	
3	COMMON EQUITY	$ 578,162,814	50.45%	0.50%	0.25%	0.25%	
4	TOTAL INVESTMENT RETURN	$ 1,156,325,628	100.90%		0.25%	0.25%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.0025

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit (W/S 1B) + Eq. AFUDC of Deprec. Exp. (Att. I)) / PTF Inv. Base (W/S 1B) x Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

6 = (0.0025 +(0 + 0) / 555,598,418) x 0.35)
7 (1 - 0.35)

8 = 0.001346

(c) State Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate / (1 - State Income Tax Rate)

9 = (0.0025 +(0 + 0) / 555,598,418) + 0.001346)* 0.08
10 (1 - 0.08)

11 = 0.000334

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.004180

		Total PTF	-
13	INVESTMENT BASE	$ 555,598,418	
14	x Cost of Capital Rate	0.0041800	
15	= Investment Return and Income Taxes	$ 2,322,401	

Notes:
(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-224, Schedule 1, Page 3 of 4, Line 14
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Western Massachusetts Electric Company (WMECO)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Worksheet 3C

					Pre-1997 PTF		Post-1996 PTF			
		(1)	(2) Wage/Plant Allocation Factors (a)	(3)	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	(6) PTF Allocation Factor (b)	(7) = (3)*(6) Post-96 PTF Allocated		
LN.		Transmission		Transmission					Reference	Notes
	Transmission Plant									
1	Transmission Plant					53,145,202		717,553,491	Attachment A2	(1)
2	General Plant	18,793,854		18,793,854	6.1211%	1,150,391	82.6455%	15,532,275	FF1 page 204 ln. 99, footnote	(1)
3	Total (line 1+2)	18,793,854		18,793,854		54,295,593		733,085,766		(1)
										(1)
4	Transmission Plant Held for Future Use	0		0	6.1211%	0	82.6455%	0	FF1 page 214 ln. 13	(1)
	Transmission Accumulated Depreciation									
5	Transmission Accum. Depreciation	54,279,720		54,279,720	6.1211%	3,322,516	82.6455%	44,859,746	FF1 page 219 ln. 25	(1)
6	General Plant Accum. Depreciation	4,371,591		4,371,591	6.1211%	267,589	82.6455%	3,612,923	FF1 page 219 ln. 28, footnote	(1)
7	Total (line 5+6)	58,651,311		58,651,311		3,590,105		48,472,669		(1)
	Transmission Accumulated Deferred Taxes									
8	Accumulated Deferred Taxes (281-283)	(225,957,746)		(225,957,746)	6.1211%	(13,831,100)	82.6455%	(186,743,909)	FF1 page 274 ln. 9 & 276 ln. 19, footnotes	(1)
9	Accumulated Deferred Taxes (190)	5,663,481 (c)		5,663,481	6.1211%	346,667	82.6455%	4,680,612	(c)	(1)
10	Total (line 8+9)	(220,294,265)		(220,294,265)		(13,484,433)		(182,063,297)		(1)
11	Transmission loss on Reacquired Debt	331,119		331,119	6.1211%	20,268	82.6455%	273,655	FF1 page 110 ln. 81, footnote	(1)
	Other Regulatory Assets									
12	Unamortized Balance of Transmission Merger-Related Costs	1,943,209		1,943,209	6.1211%	118,946	0.826455	1,605,975	**Exhibit No. ES-220, Page 4 of 8, Line 3(C)**	(2)
13	FAS 106	22,693		22,693	6.1211%	1,389	82.6455%	18,755	FF1 page 232.1 ln. 1, footnote	(1)
14	FAS 109	9,336,822		9,336,822	6.1211%	571,516	82.6455%	7,716,463	FF1 page 232 ln. 9, footnote	(1)
15	Other Regulatory Liabilities (254.DK)	(65,339)		(65,339)	6.1211%	(3,999)	82.6455%	(54,000)	FF1 page 278 ln. 5, footnote	(1)
16	Total (line 12+13+14)	11,237,385		11,237,385		687,852		9,287,193		(2)
17	Transmission Prepayments	1,023,867		1,023,867	6.1211%	62,672	82.6455%	846,180	FF1 page 110 ln. 57, footnote	(1)
18	Transmission Materials and Supplies	3,143,646		3,143,646	6.1211%	192,426	82.6455%	2,598,082	FF1 page 227 ln. 8	(1)
	Cash Working Capital									
19	Operation & Maintenance Expense					389,810		5,263,108	W/S 4C, Line 16	(1)
20	Administrative & General Expense					611,174		8,251,915	W/S 4C, Line 19	(3)
21	Transmission Support Expense					357,869			W/S 7	(1)
22	Subtotal (line 19+20+21)					1,358,853		13,515,023		(3)
23						0.125		0.125	x 45 / 360	(1)
24	Total (line 22 * line 23)					169,857		1,689,378		(3)

(a) All items are specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries and Plant Allocation Factors are not used (column 2).
(b) W/S 5A & 5B
(c)

Account 190	5,663,481	FF1 page 234 ln. 18, footnote		(1)
Less Reserve for Disputed Transactions	-	FF1 page 234 ln. 18, footnote		(1)
Total Account 190	5,663,481			(1)

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Proposed revisions reflect the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset
(3) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Western Massachusetts Electric Company (WMECO)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Worksheet 4C

					Pre-1997 PTF		Post-1996 PTF			
		(1)	(2) Wage/Plant Allocation	(3)	(4) PTF Allocation	(5) = (3)*(4) PTF	(6) PTF Allocation	(7) = (3)*(6) Post-96 PTF		
LN.		Transmission	Factors (a)	Transmission	Factor (b)	Allocated	Factor (b)	Allocated	Reference	Notes
	Depreciation Expense									
1	Transmission Depreciation	15,972,687		15,972,687	6.1211%	977,704	82.6455%	13,200,707	FF1 page 336 ln. 7	(1)
2	General Depreciation	789,658		789,658	6.1211%	48,336	82.6455%	652,617	FF1 page 336 ln. 10, footnote	(1)
3	Total (line 1+2)	16,762,345		16,762,345		1,026,040		13,853,324		(1)
4	Amortization of Loss on Reacquired Debt	49,668		49,668	6.1211%	3,040	82.6455%	41,048	FF1 page 114, ln. 64, footnote	(1)
5	Amortization of Investment Tax Credits	35,604		35,604	6.1211%	2,179	82.6455%	29,425	FF1 page 266 ln. 8(f), footnote	(1)
	Property Taxes									
6	Transmission Property Taxes	18,717,332		18,717,332	6.1211%	1,145,707	82.6455%	15,469,033	FF1 page 262 ln. 32i, footnote	(1)
7	General Property Taxes (c)				6.1211%	-	82.6455%	-		(1)
8	Total (line 6+7)	18,717,332		18,717,332		1,145,707		15,469,033		(1)
	Transmission Operation and Maintenance									
9	Operation and Maintenance	20,725,279		20,725,279	6.1211%	1,268,615	82.6455%	17,128,510	FF1 page 321 ln. 112	(1)
10	Transmission of Electricity by Others - #565	13,174,678		13,174,678	6.1211%	806,435	82.6455%	10,888,279	FF1 page 321 ln. 96	(1)
11	Account 561.1	12,368		12,368	6.1211%	757	82.6455%	10,222	FF1 page 321 ln. 85	(1)
12	Account 561.2	50,569		50,569	6.1211%	3,095	82.6455%	41,793	FF1 page 321 ln. 86	(1)
13	Account 561.3	13,262		13,262	6.1211%	812	82.6455%	10,960	FF1 page 321 ln. 87	(1)
14	Account 561.4	1,106,108		1,106,108	6.1211%	67,706	82.6455%	914,148	FF1 page 321 ln. 88	(1)
15	**Station Expenses & Rents	-			6.1211%	-	82.6455%	-	FF1 page 321 ln. 93 + ln. 98	(1)
16	O&M less lines 10 thru 15	6,368,294		6,368,294		389,810		5,263,108		(1)
	Transmission Administrative and General									
17	Administrative and General	8,041,502		8,041,502	6.1211%	492,228	82.6455%	6,645,940	FF1 page 320 ln. 197, footnote	(1)
18	Transmission Merger-Related Costs	1,943,209		1,943,209	6.1211%	118,946	82.6455%	1,605,975	**Exhibit No. ES-220, Page 4 of 8, Line 2(C)**	(2)
19	Total (line 17 + 18)					611,174		8,251,915		(2)
20	*Payroll Tax Expense*	18,291		18,291	6.1211%	1,120	82.6455%	15,117		(1)
	Federal Unemployment	283							FF1 page 262 ln. 3i, footnote	(1)
	FICA	13,202							FF1 page 262 ln. 5i, footnote	(1)
	Medicare	3,757							FF1 page 262 ln. 9i, footnote	(1)
	CT Unemployment	852							FF1 page 262 ln. 13i, footnote	(1)
	DC Unemployment	1							FF1 page 262.1 ln. 6i, footnote	(1)
	FL Unemployment	-							FF1 page 262.1 ln. 10i, footnote	(1)
	GA Unemployment	-							FF1 page 262.1 ln. 14i footnote	(1)
	MA Unemployment	69							FF1 page 262 ln. 22i, footnote	(1)
	MA Universal Health	19							FF1 page 262 ln. 27i, footnote	(1)
	MI Unemployment	-							FF1 page 262.1 ln. 14i footnote	(1)
	NH Unemployment	108							FF1 page 262 ln. 37i, footnote	(1)
	NJ Unemployment	-							FF1 page 262 footnote	(1)
	NY Unemployment	-							FF1 page 262.1, footnote	(1)
	Total	18,291	To Line 19							(1)

** To the extent that PTF Support Payments are reflected in worksheet 7 they will be excluded from this calculation.
(a) All items are specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries and Plant Allocation Factors are not used (column 2).
(b) W/S 5A & 5B
(c) Transmission related general property taxes are included in the Transmission Property tax number footnoted in the FF1.

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Exhibit No. ES-221
Schedule 5

CL&P's, PSNH's and WMECO's PTF Revenue Requirements under the Changed Rates for 2018

Eversource Energy Service Company

CL&P, PSNH and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For the Calendar Year 2018

Line	(A) Description	(B) Reference	(C) CL&P		(D) PSNH		(E) WMECO		(F)=(C)+(D)+(E) Total	
1	2014 Actual PTF Revenue Requirements		$ 460,629,964	(1)	$ 109,335,801	(2)	$ 111,781,256	(3)	$ 681,747,021	
2	Estimated 2015 PTF Plant Additions	(4)	$ 276,000,000		$ 114,000,000		$ 87,000,000		$ 477,000,000	
3	Carrying Charge Factor (CCF)	Exhibit No. ES-221, Schedule 2, Page 3 of 20, Note (3)	15.25%		16.55%		14.00%			
4	2015 Incremental Estimated PTF Revenue Requirements	Line 2 x 3	42,090,000		18,867,000		12,180,000		$ 73,137,000	
5	2015 Incremental Estimated PTF CWIP Rev. Req.	(4)	$ (19,400,000)		$ -		$ -		$ (19,400,000)	
6	Total Estimated PTF Revenue Requirement for 2015	Line 1 + 4 + 5	$ 483,319,964		$ 128,202,801		$ 123,961,256		$ 735,484,021	
7	Estimated 2016 PTF Plant Additions	(4)	$ 68,000,000		$ 117,000,000		$ 88,000,000		$ 273,000,000	
8	Carrying Charge Factor (CCF)	Line 3	15.25%		16.55%		14.00%			
9	2016 Incremental Estimated PTF Revenue Requirements	Line 7 x 8	10,370,000		19,363,500		12,320,000		$ 42,053,500	
10	Total Estimated PTF Revenue Requirement for 2016	Line 6 + 9	$ 493,689,964		$ 147,566,301		$ 136,281,256		$ 777,537,521	(5)

Notes:
(1) Exhibit No. ES-221: Schedule 5, Page 2 of 20, LN. 29(B) + Schedule 3, Page 3 of 20, LN. 29(B) + Schedule 3, Page 4 of 20, LN. 5(B) + Schedule 3, Page 5 of 20, LN. 9(B)
(2) Exhibit No. ES-221: Schedule 5, Page 2 of 20, LN. 29(C) + Schedule 3, Page 3 of 20, LN. 29(C) + Schedule 3, Page 4 of 20, LN. 5(C)
(3) Exhibit No. ES-221: Schedule 5, Page 2 of 20, LN. 29(D) + Schedule 3, Page 3 of 20, LN. 29(D) + Schedule 3, Page 4 of 20, LN. 5(D) + Schedule 3, Page 5 of 20, LN. 9(C)
(4) Based on Eversource's Forecast
(5) The revenue requirements calculations for the calendar year 2016 (including any forecast for 2016) are used as an estimate for the revenue requirements for 2018, which are used to calculate the revenue impact of the proposed cost recovery.

CL&P, PSNH and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Pre-1997

		(A)		(B)	(C)	(D)	(E)=(B)+(C)+(D)	(F)	(G)
LN.	I.	INVESTMENT BASE	Attachment F Reference Section:	CL&P	PSNH	WMECO	Total	Reference	Notes
1		Transmission Plant	(A)(1)(a)	358,812,326	88,564,672	53,145,202	500,522,200	W/S 3A,3B,3C line 1	(1)
2		General Plant	(A)(1)(b)	12,027,048	7,336,167	1,150,391	20,513,606	W/S 3A,3B,3C line 2	(1)
3		Plant Held For Future Use	(A)(1)(c)	84,157	1,138,376	0	1,222,533	W/S 3A,3B,3C line 4	(1)
4		Total Plant (Lines 1+2+3)		370,923,531	97,039,215	54,295,593	522,258,339		(1)
5		Accumulated Depreciation	(A)(1)(d)	73,042,167	17,223,185	3,590,105	93,855,457	W/S 3A,3B,3C line 7	(1)
6		Accumulated Deferred Income Taxes	(A)(1)(e)	49,105,827	16,884,906	13,484,433	79,475,166	W/S 3A,3B,3C line 10	(1)
7		Loss On Reacquired Debt	(A)(1)(f)	623,759	245,415	20,268	889,442	W/S 3A,3B,3C line 11	(1)
8		Other Regulatory Assets	(A)(1)(g)	2,278,427	1,052,873	568,906	3,900,206	W/S 3A,3B,3C line 16	(2)
9		Net Investment (Line 4-5-6+7+8)		251,677,723	64,229,412	37,810,229	353,717,364		(2)
10		Prepayments	(A)(1)(h)	1,885,610	662,602	62,672	2,610,884	W/S 3A,3B,3C line 17	(1)
11		Materials & Supplies	(A)(1)(i)	4,547,780	1,261,158	192,426	6,001,364	W/S 3A,3B,3C line 18	(1)
12		Cash Working Capital	(A)(1)(j)	1,183,771	404,847	169,857	1,758,475	W/S 3A,3B,3C line 24	(2)
13		Total Investment Base (Line 9+10+11+12)		259,294,884	66,558,019	38,235,184	364,088,087		(2)
	II.	REVENUE REQUIREMENTS							
14		Investment Return and Income Taxes	(A)	32,237,096	7,928,990	4,392,190	44,558,276	W/S 2A,2B,2C, line 15	(2)
15		Depreciation Expense	(B)	8,594,771	1,919,255	1,026,040	11,540,066	W/S 4A,4B,4C line 3	(1)
16		Amortization of Loss on Reacquired Debt	(C)	68,393	30,531	3,040	101,964	W/S 4A,4B,4C line 4	(1)
17		Investment Tax Credit	(D)	(49,341)	(600)	(2,179)	(52,120)	W/S 4A,4B,4C line 5	(1)
18		Property Tax Expense	(E)	5,226,750	2,236,785	1,145,707	8,609,242	W/S 4A,4B,4C line 8	(1)
19		Payroll Tax Expense	(F)	37,155	(505)	1,120	37,770	W/S 4A,4B,4C line 20	(1)
20		Operation & Maintenance Expense	(G)	4,360,357	1,271,570	389,810	6,021,737	W/S 4A,4B,4C line 16	(1)
21		Administrative & General Expense	(H)	5,109,811	1,462,936	611,174	7,183,921	W/S 4A,4B,4C line 19	(2)
22		Transmission Related Integrated Facilities Charge	(I)	-	-	-	-	N/A	(1)
23		Transmission Support Revenue	(J)	(2,917,925)	(376,198)	-	(3,294,123)	W/S 7	(1)
24		Transmission Support Expense	(K)	1,625,568	880,469	357,869	2,863,906	W/S 7	(1)
25		Transmission Related Expense from Generators	(L)	-	-	-	-	N/A	(1)
26		Transmission Related Taxes and Fees Charge	(M)	1,135,268	19,553	1,263	1,156,084	Attachment B, line 14	(1)
27		Revenue for ST Trans. Service Under the OATT	(N)	(68,394)	(16,040)	(8,880)	(93,314)	Attachment C, line 9	(1)
28		Transmission Rents Received from Electric Property	(O)	(5,239,993)	(1,821,957)	(402,030)	(7,463,980)	Attachment C1, line 3	(1)
29		Total Revenue Requirements (Line 14 thru 28)		50,119,516	13,534,789	7,515,124	71,169,429		(2)

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.

(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

CL&P, PSNH and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Post-1996
Worksheet 1B

		(A)		(B)	(C)	(D)	(E)=(B)+(C)+(D)	(F)	(G)
LN.	I.	INVESTMENT BASE	Attachment F Reference Section:	CL&P	PSNH	WMECO	Total	Reference	Notes
1		Transmission Plant	(A)(1)(a)	2,415,403,244	568,289,707	717,553,491	3,701,246,442	W/S 3A,3B,3C line 1	(1)
2		General Plant	(A)(1)(b)	80,962,316	47,073,591	15,532,275	143,568,182	W/S 3A,3B,3C line 2	(1)
3		Plant Held For Future Use	(A)(1)(c)	566,521	7,304,557	-	7,871,078	W/S 3A,3B,3C line 4	(1)
4		Total Plant (Lines 1+2+3)		2,496,932,081	622,667,855	733,085,766	3,852,685,702		(1)
5		Accumulated Depreciation	(A)(1)(d)	491,696,956	110,515,089	48,472,669	650,684,714	W/S 3A,3B,3C line 7	(1)
6		Accumulated Deferred Income Taxes	(A)(1)(e)	330,565,024	108,344,471	182,063,297	620,972,792	W/S 3A,3B,3C line 10	(1)
7		Loss On Reacquired Debt	(A)(1)(f)	4,198,950	1,574,739	273,655	6,047,344	W/S 3A,3B,3C line 11	(1)
8		Other Regulatory Assets	(A)(1)(g)	15,337,661	6,755,912	7,681,218	29,774,791	W/S 3A,3B,3C line 16	(2)
9		Net Investment (Line 4-5-6+7+8)		1,694,206,712	412,138,946	510,504,673	2,616,850,331		(2)
10		Prepayments	(A)(1)(h)	12,693,335	4,251,680	846,180	17,791,195	W/S 3A,3B,3C line 17	(1)
11		Materials & Supplies	(A)(1)(i)	30,614,229	8,092,403	2,598,082	41,304,714	W/S 3A,3B,3C line 18	(1)
12		Cash Working Capital	(A)(1)(j)	7,968,775	2,193,295	1,689,378	11,851,448	W/S 3A,3B,3C line 24	(2)
13		Total Investment Base Excluding CWIP (Line 9+10+11+12)		1,745,483,051	426,676,324	515,638,313	2,687,797,688		(2)
14		NEEWS Construction Work In Progress	(A)(1)(l)	164,948,530		-	164,948,530	(a)	(1)
15		Total Investment Base Including CWIP (Line 13+14)		1,910,431,581	426,676,324	515,638,313	2,852,746,218		(2)
	II.	REVENUE REQUIREMENTS							
16		Investment Return and Income Taxes	(A)	216,921,652	50,829,524	59,232,920	326,984,096	W/S 2A,2B,2C, line 15	(2)
17		Investment Return and Income Taxes-CWIP		20,499,144	-	-	20,499,144	W/S 2A,2B,2C, line 15	(1)
18		Depreciation Expense	(B)	57,857,303	12,315,183	13,853,324	84,025,810	W/S 4A,4B,4C line 3	(1)
19		Amortization of Loss on Reacquired Debt	(C)	460,401	195,905	41,048	697,354	W/S 4A,4B,4C line 4	(1)
20		Investment Tax Credit	(D)	(332,148)	(3,850)	(29,425)	(365,423)	W/S 4A,4B,4C line 5	(1)
21		Property Tax Expense	(E)	35,184,843	14,352,660	15,469,033	65,006,536	W/S 4A,4B,4C line 8	(1)
22		Payroll Tax Expense	(F)	250,119	(3,240)	15,117	261,996	W/S 4A,4B,4C line 20	(1)
23		Operation & Maintenance Expense	(G)	29,352,552	8,159,213	5,263,108	42,774,873	W/S 4A,4B,4C line 16	(1)
24		Administrative & General Expense	(H)	34,397,650	9,387,146	8,251,915	52,036,711	W/S 4A,4B,4C line 19	(2)
25		Transmission Related Integrated Facilities Charge	(I)	-	-	-	-	N/A	(1)
26		Transmission Related Expense from Generators	(L)	-	-	-	-	N/A	(1)
27		Transmission Related Taxes and Fees Charge	(M)	7,642,269	125,466	17,047	7,784,782	Attachment B line 16	(1)
28		Revenue for ST Trans. Service Under the OATT	(N)	(460,565)	(102,948)	(119,820)	(683,333)	Attachment C line 10	(1)
29		Total Revenue Requirements (Line 16 thru 28)		401,773,220	95,255,059	101,994,267	599,022,546		(2)

(a) Reflects actual information per Eversource's accounting records

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

CL&P, PSNH and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Post-2003
Worksheet 1C

	(A)	(B)	(C)	(D)	(E)=(B)+(C)+(D)	(F)	(G)
LN.	I. INVESTMENT BASE	CL&P	PSNH	WMECO	TOTAL	REFERENCE	Notes
1	Transmission Plant	$ 1,535,579,816	$ 124,215,608	$ 12,384,353	$ 1,672,179,777	Attachment D, D2, D4	(1)
2	Accumulated Depreciation	$ 213,218,089	$ 18,074,549	$ 1,442,093	$ 232,734,731	Attachment D, D2, D4	(1)
3	Accumulated Deferred Income Taxes	$ 155,340,565	$ 15,930,789	$ 2,675,475	$ 173,946,829	Attachment D1, D3, D5	(1)
4	Net Investment (Line 1-2-3)	$ 1,167,021,162	$ 90,210,270	$ 8,266,785	$ 1,265,498,217		(1)
	II. INCREMENTAL RETURN						
5	Incremental Revenue Requirements	$ 6,906,431	$ 545,953	$ 47,005	$ 7,499,389	W/S 2A,2B,2C Post 2003	(1)

Note: ROE incentives approved in FERC Opinion No. 489. As a result of Opinion No. 531-B, these projects receive an ROE incentive of 67 bp.

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.

CL&P, PSNH and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
NEEWS
Worksheet 1E

LN.	(A) I. INVESTMENT BASE	(B) CL&P	(C) WMECO	(D) = (B) + (C) Total	(E) REFERENCE	(F) Notes
1	Transmission Plant	$ 200,288,632	$ 556,313,751	$ 756,602,383	Attachment F & F2	(1)
2	Accumulated Depreciation	$ 8,946,318	$ 22,283,705	$ 31,230,023	Attachment F & F2	(1)
3	Accumulated Deferred Income Taxes	$ 46,929,968	$ 142,742,742	$ 189,672,710	Attachment F1 & F3	(1)
4	Net Investment Excluding CWIP(Line 1-2-3)	$ 144,412,346	$ 391,287,304	$ 535,699,650		(1)
5	NEEWS Construction Work In Progress	$ 164,948,530	$ -	$ 164,948,530	Attachment F & F2	(1)
6	Net Investment Including CWIP(Line 4+5)	$ 309,360,876	$ 391,287,304	$ 700,648,180		(1)
	II. INCREMENTAL RETURN					
7	Incremental Revenue Requirements	$ 854,632	$ 2,224,860	$ 3,079,492	W/S 2A & 2C NEEWS	(1)
8	Incremental Revenue Requirements-CWIP	$ 976,165	$ -	$ 976,165	W/S 2A & 2C NEEWS	(1)
9	Total Incremental Revenue Requirements (line 7+8)	$ 1,830,797	$ 2,224,860	$ 4,055,657		(1)

Note: Incentives approved in FERC Docket No. ER08-1548. As a result of Opinion No. 531-B, this project receives ROE incentives of 67 bp.

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.

Connecticut Light & Power Company (CL&P)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Investment Return and Income Taxes - Pre 1997
Worksheet 2A

Line	(A)		(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$	2,579,060,322	45.78%	5.36%	2.45%		
2	PREFERRED STOCK	$	116,868,097	2.07%	4.80%	0.10%	0.10%	
3	COMMON EQUITY	$	2,938,441,767	52.15%	11.07%	5.77%	5.77%	
4	TOTAL INVESTMENT RETURN	$	5,634,370,186	100.00%		8.32%	5.87%	

Cost of Capital Rate=

Line												
5	(a) Weighted Cost of Capital	=	0.0832									
					PTF Inv.		Eq. AFUDC					
	(b) Federal Income Tax	= (	R.O.E. +	(	(Tax Credit (W/S 1A)	+	of Deprec. Exp. (Att. I)	) /	PTF Inv. Base (W/S 1A)	x	Federal Income Tax Rate)	
							(1 - Federal Income Tax Rate)					
6		=	0.0587	+(	(49,341)	+	269,748	) /	259,294,884	) x	0.35)	
7							(1	-	0.35	)		
8		=	0.032065									
					PTF Inv.		Eq. AFUDC					
	(c) State Income Tax	=	R.O.E. +	(	(Tax Credit	+	of Deprec. Exp.	) /	PTF Inv. Base)	+	Federal Income Tax)*State Income Tax Rate	
							(1 - State Income tax Rate)					
9		=	0.0587	+(	(49,341)	+	269,748	) /	259,294,884	) +	0.032065	)* 0.09
10							(1	-	0.09	)		
11		=	0.009061									
12	(a)+(b)+(c) **Cost of Capital Rate**	=	0.124326									

Line			Pre-1997 PTF	
13	INVESTMENT BASE	$	259,294,884	From Worksheet 1A, line 13
14	x Cost of Capital Rate		0.124326	
15	= Investment Return and Income Taxes	$	32,237,096	To Worksheet 1A, line 14

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) The balance in "Total Inv. Base" is revised under the Changed Rates

Connecticut Light & Power Company (CL&P)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Investment Return and Income Taxes - Post 1996
Worksheet 2A

Line	(A)	(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 2,579,060,322	45.78%	5.36%	2.45%		
2	PREFERRED STOCK	$ 116,868,097	2.07%	4.80%	0.10%	0.10%	
3	COMMON EQUITY	$ 2,938,441,767	52.15%	11.07%	5.77%	5.77%	
4	TOTAL INVESTMENT RETURN	$ 5,634,370,186	100.00%		8.32%	5.87%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.0832

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit (W/S 1B) + Eq. AFUDC of Deprec. Exp. (Att. I)) / PTF Inv. Base (W/S 1B) x Federal Income Tax Rate)
(1 - Federal Income Tax Rate)

6 = 0.0587 +((332,148) + 1,815,862) / 1,910,431,581) x 0.35)
7 (1 - 0.35)

8 = 0.032026

(c) State Income Tax = R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate
(1 - State Income tax Rate)

9 = 0.0587 +((332,148) + 1,815,862) / 1,910,431,581) + 0.032026)* 0.09
10 (1 - 0.09)

11 = 0.009050

12 (a)+(b)+(c) Cost of Capital Rate = 0.124276

Line		Post - 1996 Total PTF	-	Post - 1996 PTF CWIP	=	Post -1996 PTF Excluding CWIP	
13	INVESTMENT BASE	$ 1,910,431,581		$ 164,948,530		$ 1,745,483,051	From Worksheet 1B, line 13, 14
14	x Cost of Capital Rate	0.124276		0.124276		0.124276	
15	= Investment Return and Income Taxes	$ 237,420,795		$ 20,499,144		$ 216,921,652	To Worksheet 1B, line 16

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) The balance in "Total Inv. Base" is revised under the Changed Rates

Connecticut Light & Power Company (CL&P)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Investment Return and Income Taxes - 50bp

Line	(A)		(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$	2,579,060,322	45.78%		0.00%		
2	PREFERRED STOCK	$	116,868,097	2.07%		0.00%	0.00%	
3	COMMON EQUITY	$	2,938,441,767	52.15%	0.50%	0.26%	0.26%	
4	TOTAL INVESTMENT RETURN	$	5,634,370,186	100.00%		0.26%	0.26%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.0026

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit (W/S 1B) + Eq. AFUDC of Deprec. Exp. (Att. I)) / PTF Inv. Base (W/S 1B) x Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

6 = 0.0026 +(0 + 0) / 2,169,726,465) x 0.35)
7 (1 - 0.35)

8 = 0.001400

(c) State Income Tax = R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate / (1 - State Income tax Rate)

9 = 0.0026 +(0 + 0) / 2,169,726,465) + 0.001400)* 0.09
10 (1 - 0.09)

11 = 0.000396

12 (a)+(b)+(c) Cost of Capital Rate = 0.004396

Line			Total PTF
13	INVESTMENT BASE	$	2,169,726,465
14	x Cost of Capital Rate		0.004396
15	= Investment Return and Income Taxes	$	9,538,118

Notes:
(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-224, Schedule 1, Page 4 of 4, Line 14
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Connecticut Light & Power Company (CL&P)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Worksheet 3A

LN.		(1) Transmission	(2) Wage/Plant Allocation Factors (a)	(3) Transmission	Pre-1997 PTF (4) PTF Allocation Factor (b)	Pre-1997 PTF (5) = (3)*(4) PTF Allocated	Post-1996 PTF (6) PTF Allocation Factor (b)	Post-1996 PTF (7) = (3)*(6) PTF Allocated	Reference	Notes
	Transmission Plant									
1	Transmission Plant					358,812,326		2,415,403,244	Attachment A (H1)	(1)
2	General Plant	104,400,554		104,400,554	11.5201%	12,027,048	77.5497%	80,962,316	FF1 page 204 ln. 99, footnote	(1)
3	Total (line 1+2)	104,400,554		104,400,554		370,839,374		2,496,365,560		(1)
										(1)
4	Transmission Plant Held for Future Use	730,526 (c)		730,526	11.5201%	84,157	77.5497%	566,521	(c)	(1)
	Transmission Accumulated Depreciation									
5	Transmission Accum. Depreciation	605,238,764		605,238,764	11.5201%	69,724,111	77.5497%	469,360,846	FF1 page 219 ln. 25	(1)
6	General Plant Accum. Depreciation	28,802,317		28,802,317	11.5201%	3,318,056	77.5497%	22,336,110	FF1 page 219 ln. 28, footnote	(1)
7	Total (line 5+6)	634,041,081		634,041,081		73,042,167		491,696,956	Schedule 2, Page 6,7,8	(1)
	Transmission Accumulated Deferred Taxes									
8	Accumulated Deferred Taxes (281 to 283)	(470,775,688)		(470,775,688)	11.5201%	(54,233,830)	77.5497%	(365,085,134)	FF1 page 274 ln. 9 & 276 ln. 19 fns	(1)
9	Accumulated Deferred Taxes (190)	44,513,531 (d)		44,513,531	11.5201%	5,128,003	77.5497%	34,520,110	(d)	(1)
10	Total (line 8+9)	(426,262,157)		(426,262,157)		(49,105,827)		(330,565,024)		(1)
11	Transmission loss on Reacquired Debt	5,414,528		5,414,528	11.5201%	623,759	77.5497%	4,198,950	FF1 page 110 ln. 81, footnote	(1)
	Other Regulatory Assets									
12	Unamortized Balance of Transmission Merger-Related Costs	-		-	11.5201%	-	77.5497%	-	**Exhibit No. ES-220, Page 1 of 8, Line 3(D)**	(2)
13	FAS 106	66,791		66,791	11.5201%	7,694	77.5497%	51,796	FF1 page 232 Ln. 27, footnote	(1)
14	FAS 109	23,019,567		23,019,567	11.5201%	2,651,877	77.5497%	17,851,605	FF1 page 232 ln. 7, footnote	(1)
15	Other Regulatory Liabilities (254.DK)	(3,308,510)		(3,308,510)	11.5201%	(381,144)	77.5497%	(2,565,740)	FF1 page 278 ln. 3, footnote	(1)
16	Total (line 12+13+14)	19,777,848		19,777,848		2,278,427		15,337,661		(2)
17	Transmission Prepayments (165)	16,368,000		16,368,000	11.5201%	1,885,610	77.5497%	12,693,335	FF1 page 110 ln. 57, footnote	(1)
18	Transmission Materials and Supplies	39,476,915		39,476,915	11.5201%	4,547,780	77.5497%	30,614,229	FF1 page 227 ln. 8	(1)
	Cash Working Capital									
19	Operation & Maintenance Expense					4,360,357		29,352,552	W/S 4A, Line 16	(1)
20	Administrative & General Expense					5,109,811		34,397,650	W/S 4A, Line 19	(3)
21	Transmission Support Expense					-		-	W/S 7	(1)
22	Subtotal (line 18+19+20)					9,470,168		63,750,202		(3)
23						0.125		0.125	x 45 / 360	(1)
24	Total (line 21 * line 22)					1,183,771		7,968,775		(3)

(a) All items are specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries and Plant Allocation Factors are not used (colum
(b) W/S 5A & 5B

(c)	Account 105	32,127,498	FF1 page 214 ln. 33	(1)
	Less Third Underground Conduit Duct	31,396,972	FF1 page 214 ln. 22	(1)
		730,526		(1)
(d)	Account 190	46,955,376	FF1 page 234 ln. 18, footnote	(1)
	Less Reserve for Disputed Transactions	2,441,845	FF1 page 234 ln. 18, footnote	(1)
	Total Account 190	44,513,531		(1)

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Proposed revisions reflect the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset
(3) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Connecticut Light & Power Company (CL&P)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Worksheet 4A

					PRE-97 PTF		POST-96 PTF			
		(1)	(2)	(3)	(4)	(5) = (3)*(4)	(6)	(7) = (3)*(6)		
LN.		Transmission	Wage/Plant Allocation Factors (a)	Transmission	PTF Allocation Factor (b)	PTF Allocated	PTF Allocation Factor (b)	Post-96 PTF Allocated	Reference	Notes
	Depreciation Expense									
1	Transmission Depreciation	69,626,166		69,626,166	11.5201%	8,021,004	77.5497%	53,994,883	FF1 page 336 ln. 7	(1)
2	General Depreciation	4,980,574		4,980,574	11.5201%	573,767	77.5497%	3,862,420	FF1 page 336 ln. 10, footnote	(1)
3	Total (line 1+2)	74,606,740		74,606,740		8,594,771		57,857,303		(1)
4	Amortization of Loss on Reacquired Debt	593,685		593,685	11.5201%	68,393	77.5497%	460,401	FF1 page 114 ln. 64, footnote	(1)
5	Amortization of Investment Tax Credits	428,304		428,304	11.5201%	49,341	77.5497%	332,148	FF1 page 266 ln. 8(f), footnote	(1)
	Property Taxes									
6	Transmission Property Taxes	45,370,701		45,370,701	11.5201%	5,226,750	77.5497%	35,184,843	FF1 page 262 ln. 25i, footnote	(1)
7	General Property Taxes (c)	-		-	11.5201%	-	77.5497%	-		(1)
8	Total (line 6+7)	45,370,701		45,370,701		5,226,750		35,184,843		(1)
	Transmission Operation and Maintenance									
9	Operation and Maintenance	77,432,007		77,432,007	11.5201%	8,920,245	77.5497%	60,048,289	FF1 page 321 ln. 112	(1)
10	Transmission of Electricity by Others - #565	21,727,966		21,727,966	11.5201%	2,503,083	77.5497%	16,849,972	FF1 page 321 ln. 96	(1)
11	Account 561.1	3,245,594		3,245,594	11.5201%	373,896	77.5497%	2,516,948	FF1 page 321 ln. 85	(1)
12	Account 561.2	5,212,556		5,212,556	11.5201%	600,492	77.5497%	4,042,322	FF1 page 321 ln. 86	(1)
13	Account 561.3	2,238,612		2,238,612	11.5201%	257,890	77.5497%	1,736,037	FF1 page 321 ln. 87	(1)
14	Account 561.4	7,157,291		7,157,291	11.5201%	824,527	77.5497%	5,550,458	FF1 page 321 ln. 88	(1)
15	**Station Expenses & Rents	-		-	11.5201%	-	77.5497%	-	FF1 page 321 ln. 93 + ln. 98	(1)
16	O&M less lines 10 thru 15	37,849,988		37,849,988		4,360,357		29,352,552		(1)
	Transmission Administrative and General									
17	Administrative and General	37,202,294		37,202,294	11.5201%	4,285,741	77.5497%	28,850,267	FF1 page 320 ln. 197 b, footnote	(1)
18	Transmission Merger-Related Costs	7,153,326		7,153,326	11.5201%	824,070	77.5497%	5,547,383	**Exhibit No. ES-220, Page 1 of 8, Line 2(D)**	(2)
19	Total (line 17 + 18)					5,109,811		34,397,650		(2)
20	*Payroll Tax Expense*	322,527		322,527	11.5201%	37,155	77.5497%	250,119		(1)
	Federal Unemployment	5,226							FF1 page 262 ln. 3i, footnote	(1)
	FICA	233,351							FF1 page 262 ln. 5i, footnote	(1)
	Medicare	65,613							FF1 page 262 ln. 9i, footnote	(1)
	CT Unemployment	16,786							FF1 page 262 ln. 15i, footnote	(1)
	DC Unemployment	11							FF1 page 262.1 ln. 14i, footnote	(1)
	FL Unemployment	1							FF1 page 262.1 ln. 18i, footnote	(1)
	GA Unemployment	-							FF1 page 262 footnote	(1)
	MA Unemployment	(285)							FF1 page 262 ln. 32i, footnote	(1)
	MA Universal Health	64							FF1 page 262 ln. 33i, footnote	(1)
	MI Unemployment	6							FF1 page 262.1 ln. 22i, footnote	(1)
	NH Unemployment	1,754							FF1 page 262.1 ln. 4i, footnote	(1)
	NJ Unemployment	-							FF1 page 262 footnote	(1)
	NY Unemployment	-							FF1 page 262.1 ln. 10i, footnote	(1)
	Total	322,527	To Line 18							(1)

** To the extent that PTF Support Payments are reflected in worksheet 7 they will be excluded from this calculation.
(a) All items are specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries and Plant Allocation Factors are not used (column 2).
(b) W/S 5A & 5B
(c) Transmission related general property taxes are included in the Transmission Property tax number footnoted in the FF1.

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Public Service Company of New Hampshire (PSNH)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Investment Return and Income Taxes - Pre 1997
Worksheet 2B

Line	(A)	(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 1,070,020,120	46.56%	4.15%	1.93%		
2	PREFERRED STOCK	$ -	0.00%	0.00%	0.00%	0.00%	
3	COMMON EQUITY	$ 1,228,095,985	53.44%	11.07%	5.92%	5.92%	
4	TOTAL INVESTMENT RETURN	$ 2,298,116,105	100.00%		7.85%	5.92%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.0785

(b) Federal Income Tax =((R.O.E. + (PTF Inv. (Tax Credit (W/S 1A) + Eq. AFUDC of Deprec. Exp. (Att. I)) / PTF Inv. Base (W/S 1A) x Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

6 =(0.0592 +((600) + 29,005) / 66,558,019) x 0.35)
7 (1 - 0.35)

8 = 0.032107

(c) State Income Tax =(R.O.E. + +(PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate / (1 - State Income Tax Rate)

9 =(0.0592 +((600) + 29,005) / 66,558,019) + 0.032107)* 0.085
10 (1 - 0.085)

11 = 0.008522

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.119129

		Pre-1997 PTF	
13	INVESTMENT BASE	$ 66,558,019	From Worksheet 1A, line 13
14	x Cost of Capital Rate	0.1191290	
15	= Investment Return and Income Taxes	$ 7,928,990	To Worksheet 1A, line 14

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) The balance in "Total Inv. Base" is revised under the Changed Rates

Public Service Company of New Hampshire (PSNH)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Investment Return and Income Taxes - Post 1996
Worksheet 2B

Line	(A)	(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 1,070,020,120	46.56%	4.15%	1.93%		
2	PREFERRED STOCK	$ -	0.00%	0.00%	0.00%	0.00%	
3	COMMON EQUITY	$ 1,228,095,985	53.44%	11.07%	5.92%	5.92%	
4	TOTAL INVESTMENT RETURN	$ 2,298,116,105	100.00%		7.85%	5.92%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.0785

(b) Federal Income Tax = ((R.O.E. + (PTF Inv. (Tax Credit (W/S 1B) + Eq. AFUDC of Deprec. Exp. (Att. I)) / PTF Inv. Base (W/S 1A) x Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

6 = (0.0592 +((3,850) + 186,109) / 426,676,324) x 0.35)
7 (1 - 0.35)

8 = 0.032107

(c) State Income Tax = (R.O.E. + +(PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate / (1 - State Income Tax Rate)

9 = (0.0592 +((3,850) + 186,109) / 426,676,324) + 0.032107)* 0.085
10 (1 - 0.085)

11 = 0.008522

12 (a)+(b)+(c) Cost of Capital Rate = 0.119129

Line		Post - 1996Total PTF	
13	INVESTMENT BASE	$ 426,676,324	From Worksheet 1A, line 13
14	x Cost of Capital Rate	0.119129	
15	= Investment Return and Income Taxes	$ 50,829,524	To Worksheet 1B, line 16

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) The balance in "Total Inv. Base" is revised under the Changed Rates

Public Service Company of New Hampshire (PSNH)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Investment Return and Income Taxes - 50bp

Line	(A)		(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$	1,070,020,120	46.56%		0.00%		
2	PREFERRED STOCK	$	-	0.00%		0.00%	0.00%	
3	COMMON EQUITY	$	1,228,095,985	53.44%	0.50%	0.27%	0.27%	
4	TOTAL INVESTMENT RETURN	$	2,298,116,105	100.00%		0.27%	0.27%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.0027

(b) Federal Income Tax = ((R.O.E. + (PTF Inv. (Tax Credit (W/S 1B) + Eq. AFUDC of Deprec. Exp. (Att. I)) / PTF Inv. Base (W/S 1A) x Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

6 = (0.0027 +(0 + 0) / 493,234,343) x 0.35)
7 (1 - 0.35)

8 = 0.001454

(c) State Income Tax = (R.O.E. + +(PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate / (1 - State Income Tax Rate)

9 = (0.0027 +(0 + 0) / 493,234,343) + 0.001454)* 0.085
10 (1 - 0.085)

11 = 0.000386

12 (a)+(b)+(c) Cost of Capital Rate = 0.004540

Line			Total PTF
13	INVESTMENT BASE	$	493,234,343
14	x Cost of Capital Rate		0.004540
15	= Investment Return and Income Taxes	$	2,239,284

Notes:

(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-224, Schedule 1, Page 4 of 4, Line 14
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Public Service Company of New Hampshire (PSNH)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Worksheet 3B

LN.		(1) Transmission	(2) Wage/Plant Allocation Factors (a)	(3) Transmission	Pre-1997 PTF (4) PTF Allocation Factor (b)	Pre-1997 PTF (5) = (3)*(4) PTF Allocated	Post-1996 PTF (6) PTF Allocation Factor (b)	Post-1996 PTF (7) = (3)*(6) Post-96 PTF Allocated	Reference	Notes
	Transmission Plant									
1	Transmission Plant					88,564,672		568,289,707	Attachment A1	(1)
2	General Plant	59,322,426		59,322,426	12.3666%	7,336,167	79.3521%	47,073,591	FF1 page 204 ln. 99, footnote	(1)
3	Total (line 1+2)	59,322,426		59,322,426		95,900,839		615,363,298		(1)
										(1)
4	Transmission Plant Held for Future Use	9,205,247		9,205,247	12.3666%	1,138,376	79.3521%	7,304,557	FF1 page 214 ln. 35	(1)
	Transmission Accumulated Depreciation									
5	Transmission Accum. Depreciation	123,132,357		123,132,357	12.3666%	15,227,286	79.3521%	97,708,111	FF1 page 219 ln. 25	(1)
6	General Plant Accum. Depreciation	16,139,432		16,139,432	12.3666%	1,995,899	79.3521%	12,806,978	FF1 page 219 ln. 28, footnote	(1)
7	Total (line 5+6)	139,271,789		139,271,789		17,223,185		110,515,089		(1)
	Transmission Accumulated Deferred Taxes									
8	Accumulated Deferred Taxes (281-283)	(145,475,861)		(145,475,861)	12.3666%	(17,990,418)	79.3521%	(115,438,151)	FF1 page 274 ln. 9 & 276 ln. 19 fns	(1)
9	Accumulated Deferred Taxes (190)	8,939,499 (c)		8,939,499	12.3666%	1,105,512	79.3521%	7,093,680	(c)	(1)
10	Total (line 8+9)	(136,536,362)		(136,536,362)		(16,884,906)		(108,344,471)		(1)
				-						
11	Transmission loss on Reacquired Debt	1,984,496		1,984,496	12.3666%	245,415	79.3521%	1,574,739	FF1 page 110 ln. 81, footnote	(1)
	Other Regulatory Assets									
12	Unamortized Balance of Transmission Merger-Related Costs	-		-	0.123666	-	0.793521	-	**Exhibit No. ES-220, Page 3 of 8, Line 3(D)**	(2)
13	FAS 106	350,591		350,591	12.3666%	43,356	79.3521%	278,201	FF1 page 232.1 ln. 15, footnote	(1)
14	FAS 109	8,171,016		8,171,016	12.3666%	1,010,477	79.3521%	6,483,873	FF1 page 232 ln. 1, footnote	(1)
15	Other Regulatory Liabilities (254.DK)	(7,765)		(7,765)	12.3666%	(960)	79.3521%	(6,162)	FF1 page 278 ln. 1, footnote	(1)
16	Total (line 12+13+14)	8,513,842		8,513,842		1,052,873		6,755,912		(2)
17	Transmission Prepayments	5,357,993		5,357,993	12.3666%	662,602	79.3521%	4,251,680	FF1 page 110 ln. 57, footnote	(1)
18	Transmission Materials and Supplies	10,198,096		10,198,096	12.3666%	1,261,158	79.3521%	8,092,403	FF1 page 227 ln. 8	(1)
	Cash Working Capital									
19	Operation & Maintenance Expense					1,271,570		8,159,213	W/S 4B, Line 16	(1)
20	Administrative & General Expense					1,462,936		9,387,146	W/S 4B, Line 19	(3)
21	Transmission Support Expense					504,271		-	W/S 7	(1)
22	Subtotal (line 18+19+20)					3,238,777		17,546,359		(3)
23						0.125		0.125	x 45 / 360	(1)
24	Total (line 21 * line 22)					404,847		2,193,295		(3)

(a) All items are specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries and Plant Allocation Factors are not used (column 2).
(b) W/S 5A & 5B
(c)

Account 190	8,939,499	FF1 page 234 ln. 18, footnote	(1)
Less Reserve for Disputed Transactions	-	FF1 page 234 ln. 18, footnote	(1)
Total Account 190	8,939,499		(1)

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Proposed revisions reflect the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset
(3) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expense

Public Service Company of New Hampshire (PSNH)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Worksheet 4B

					Pre-1997 PTF		Post-1996 PTF			
		(1)	(2) Wage/Plant Allocation	(3)	(4) PTF Allocation	(5) = (3)*(4) PTF	(6) PTF Allocation	(7) = (3)*(6) Post-96 PTF		
LN.		Transmission	Factors (a)	Transmission	Factor (b)	Allocated	Factor (b)	Allocated	Reference	Notes
	Depreciation Expense									
1	Transmission Depreciation	12,792,512		12,792,512	12.3666%	1,581,999	79.3521%	10,151,127	FF 1 page 336 ln. 7	(1)
2	General Depreciation	2,727,156		2,727,156	12.3666%	337,256	79.3521%	2,164,056	FF1 page 336 ln. 10, footnote	(1)
3	Total (line 1+2)	15,519,668		15,519,668		1,919,255		12,315,183		(1)
4	Amortization of Loss on Reacquired Debt	246,881		246,881	12.3666%	30,531	79.3521%	195,905	FF1 page 114 ln. 64, footnote	(1)
5	Amortization of Investment Tax Credits	4,852		4,852	12.3666%	600	79.3521%	3,850	FF1 page 266 ln. 8(f), footnote	(1)
	Property Taxes									
6	Transmission Property Taxes	18,087,310		18,087,310	12.3666%	2,236,785	79.3521%	14,352,660	FF1 page 262 ln. 23i + ln. 30i +	(1)
7	General Property Taxes (c)	-		-	12.3666%	-	79.3521%	-	page 262.1 ln. 2i, footnote	(1)
8	Total (line 6+7)	18,087,310		18,087,310		2,236,785		14,352,660		(1)
	Transmission Operation and Maintenance									
9	Operation and Maintenance	51,082,852		51,082,852	12.3666%	6,317,212	79.3521%	40,535,316	FF1 page 321 ln. 112	(1)
10	Transmission of Electricity by Others - #565	37,174,569		37,174,569	12.3666%	4,597,230	79.3521%	29,498,801	FF1 page 321 ln. 96	(1)
11	Account 561.1	653,575		653,575	12.3666%	80,825	79.3521%	518,625	FF1 page 321 ln. 85	(1)
12	Account 561.2	474,690		474,690	12.3666%	58,703	79.3521%	376,676	FF1 page 321 ln. 86	(1)
13	Account 561.3	36,962		36,962	12.3666%	4,571	79.3521%	29,330	FF1 page 321 ln. 87	(1)
14	Account 561.4	2,460,768		2,460,768	12.3666%	304,313	79.3521%	1,952,671	FF1 page 321 ln. 88	(1)
15	**Station Expenses & Rents	-		-	12.3666%	-	79.3521%	-	FF1 page 321 ln. 93 + ln. 98	(1)
16	O&M less lines 10 thru 15	10,282,288		10,282,288		1,271,570		8,159,213		(1)
	Transmission Administrative and General									
17	Administrative and General	10,348,117		10,348,117	12.3666%	1,279,710	79.3521%	8,211,448	FF1 page 320 ln. 197 b, footnote	(1)
18	Transmission Merger-Related Costs	1,481,622		1,481,622	12.3666%	183,226	79.3521%	1,175,698	**Exhibit No. ES-220, Page 3 of 8, Line 2(D)**	(2)
19	Total (line 17 + 18)					1,462,936		9,387,146		(2)
20	*Payroll Tax Expense*	(4,083)		(4,083)	12.3666%	(505)	79.3521%	(3,240)		(1)
	Federal Unemployment	(51)							FF1 page 262 ln. 2i, footnote	(1)
	FICA	(3,062)							FF1 page 262 ln. 4i, footnote	(1)
	Medicare	(816)							FF1 page 262 ln. 7i, footnote	(1)
	CT Unemployment	(128)							FF1 page 262.1 ln. 7i, footnote	(1)
	DC Unemployment	0							FF1 page 262 ln. 26i, footnote	(1)
	FL Unemployment	0							FF1 page 262.1 ln. 27i, footnote	(1)
	GA Unemployment	0							FF1 page 262.1, footnote	(1)
	MA Unemployment	2							FF1 page 262.1 ln. 15i, footnote	(1)
	MA Universal Health	(1)							FF1 page 262.1 ln. 16i, footnote	(1)
	MI Unemployment	0							FF1 page 262.1 ln. 31i, footnote	(1)
	NH Unemployment	(27)							FF1 page 262 ln. 14i, footnote	(1)
	NJ Unemployment	0							FF1 page 262, footnote	(1)
	NY Unemployment	0							FF1 page 262 footnote	(1)
	Total	(4,083)	To Line 19							(1)

** To the extent that PTF Support Payments are reflected in worksheet 7 they will be excluded from this calculation.

(a) All items are specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries and Plant Allocation Factors are not used (column 2).

(b) W/S 5A & 5B

(c) Transmission related general property taxes are included in the Transmission Property tax number footnoted in the FF1.

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-00

(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expense

Western Massachusetts Electric Company (WMECO)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Investment Return and Income Taxes - Pre 1997
Worksheet 2C

Line	(A)	(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 567,833,428	49.55%	4.31%	2.14%		
2	PREFERRED STOCK	$ -	0.00%	0.00%	0.00%	0.00%	
3	COMMON EQUITY	$ 578,162,814	50.45%	11.07%	5.58%	5.58%	
4	TOTAL INVESTMENT RETURN	$ 1,145,996,242	100.00%		7.72%	5.58%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.0772

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit (W/S 1A) + Eq. AFUDC of Deprec. Exp. (Att. I)) / PTF Inv. Base (W/S 1A) x Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

6 = (0.0558 +((2,179) + 11,396) / 38,235,184) x 0.35)
7 (1 - 0.35)

8 = 0.030176

(c) State Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate / (1 - State Income Tax Rate)

9 = (0.0558 +((2,179) + 11,396) / 38,235,184) + 0.030176)* 0.08
10 (1 - 0.08)

11 = 0.007497

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.114873

Line		**Pre-1997 PTF**	
13	INVESTMENT BASE	$ 38,235,184	From Worksheet 1A, line 13
14	x Cost of Capital Rate	0.114873	
15	= Investment Return and Income Taxes	$ 4,392,190	To Worksheet 1A, line 14

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) The balance in "Total Inv. Base" is revised under the Changed Rates

Western Massachusetts Electric Company (WMECO)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014

Investment Return and Income Taxes - Post 1996

Worksheet 2C

Line	(A)	(B) CAPITALIZATION 12/31/2014 (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 567,833,428	49.55%	4.31%	2.14%		
2	PREFERRED STOCK	$ -	0.00%	0.00%	0.00%	0.00%	
3	COMMON EQUITY	$ 578,162,814	50.45%	11.07%	5.58%	5.58%	
4	TOTAL INVESTMENT RETURN	$ 1,145,996,242	100.00%		7.72%	5.58%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.0772

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit (W/S 1B) + Eq. AFUDC of Deprec. Exp. (Att. I)) / PTF Inv. Base (W/S 1B) x Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

6 = (0.0558 +((29,425) + 153,859) / 515,638,313) x 0.35)
7 (1 - 0.35)

8 = 0.030176

(c) State Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate / (1 - State Income Tax Rate)

9 = (0.0558 +((29,425) + 153,859) / 515,638,313) + 0.030176)* 0.08
10 (1 - 0.08)

11 = 0.007497

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.114873

Line		**Post - 1996 Total PTF**	-	**Post - 1996 PTF CWIP**	=	**Post -1996 PTF Excluding CWIP**	
13	INVESTMENT BASE	$ 515,638,313		$ -		$ 515,638,313	From Worksheet 1B, line 13, 14
14	x Cost of Capital Rate	0.1148730		0.1148730		0.1148730	
15	= Investment Return and Income Taxes	$ 59,232,920		$ -		$ 59,232,920	To Worksheet 1A, line 14

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) The balance in "Total Inv. Base" is revised under the Changed Rates

Western Massachusetts Electric Company (WMECO)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014

Investment Return and Income Taxes - 50bp

Line	(A)	(B) CAPITALIZATION (B) (Attachment H)	(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL	(E) WEIGHTED COST OF CAPITAL	(F) EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 578,162,814	50.45%		0.00%		
2	PREFERRED STOCK		0.00%		0.00%	0.00%	
3	COMMON EQUITY	$ 578,162,814	50.45%	0.50%	0.25%	0.25%	
4	TOTAL INVESTMENT RETURN	$ 1,156,325,628	100.90%		0.25%	0.25%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.0025

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit (W/S 1B) + Eq. AFUDC of Deprec. Exp. (Att. I)) / PTF Inv. Base (W/S 1B) x Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

6 = (0.0025 +(0 + 0) / 553,873,497) x 0.35)
7 (1 - 0.35)

8 = 0.001346

(c) State Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate / (1 - State Income Tax Rate)

9 = (0.0025 +(0 + 0) / 553,873,497) + 0.001346)* 0.08
10 (1 - 0.08)

11 = 0.000334

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.004180

Line		**Total PTF**
13	INVESTMENT BASE	$ 553,873,497
14	x Cost of Capital Rate	0.0041800
15	= Investment Return and Income Taxes	$ 2,315,191

Notes:
(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-224, Schedule 1, Page 4 of 4, Line 14
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Western Massachusetts Electric Company (WMECO)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Worksheet 3C

					Pre-1997 PTF		Post-1996 PTF			
		(1)	(2)	(3)	(4)	(5) = (3)*(4)	(6)	(7) = (3)*(6)		
			Wage/Plant		PTF		PTF	Post-96		
			Allocation		Allocation	PTF	Allocation	PTF		
LN.		Transmission	Factors (a)	Transmission	Factor (b)	Allocated	Factor (b)	Allocated	Reference	Notes
	Transmission Plant									
1	Transmission Plant					53,145,202		717,553,491	Attachment A2	(1)
2	General Plant	18,793,854		18,793,854	6.1211%	1,150,391	82.6455%	15,532,275	FF1 page 204 ln. 99, footnote	(1)
3	Total (line 1+2)	18,793,854		18,793,854		54,295,593		733,085,766		(1)
										(1)
4	Transmission Plant Held for Future Use	0		0	6.1211%	0	82.6455%	0	FF1 page 214 ln. 13	(1)
	Transmission Accumulated Depreciation									
5	Transmission Accum. Depreciation	54,279,720		54,279,720	6.1211%	3,322,516	82.6455%	44,859,746	FF1 page 219 ln. 25	(1)
6	General Plant Accum. Depreciation	4,371,591		4,371,591	6.1211%	267,589	82.6455%	3,612,923	FF1 page 219 ln. 28, footnote	(1)
7	Total (line 5+6)	58,651,311		58,651,311		3,590,105		48,472,669		(1)
	Transmission Accumulated Deferred Taxes									
8	Accumulated Deferred Taxes (281-283)	(225,957,746)		(225,957,746)	6.1211%	(13,831,100)	82.6455%	(186,743,909)	FF1 page 274 ln. 9 & 276 ln. 19, footnotes	(1)
9	Accumulated Deferred Taxes (190)	5,663,481 (c)		5,663,481	6.1211%	346,667	82.6455%	4,680,612	(c)	(1)
10	Total (line 8+9)	(220,294,265)		(220,294,265)		(13,484,433)		(182,063,297)		(1)
11	Transmission loss on Reacquired Debt	331,119		331,119	6.1211%	20,268	82.6455%	273,655	FF1 page 110 ln. 81, footnote	(1)
	Other Regulatory Assets									
12	Unamortized Balance of Transmission Merger-Related Costs	-		-	6.1211%	-	0.826455	-	**Exhibit No. ES-220, Page 4 of 8, Line 3(D)**	(2)
13	FAS 106	22,693		22,693	6.1211%	1,389	82.6455%	18,755	FF1 page 232.1 ln. 1, footnote	(1)
14	FAS 109	9,336,822		9,336,822	6.1211%	571,516	82.6455%	7,716,463	FF1 page 232 ln. 9, footnote	(1)
15	Other Regulatory Liabilities (254.DK)	(65,339)		(65,339)	6.1211%	(3,999)	82.6455%	(54,000)	FF1 page 278 ln. 5, footnote	(1)
16	Total (line 12+13+14)	9,294,176		9,294,176		568,906		7,681,218		(2)
17	Transmission Prepayments	1,023,867		1,023,867	6.1211%	62,672	82.6455%	846,180	FF1 page 110 ln. 57, footnote	(1)
18	Transmission Materials and Supplies	3,143,646		3,143,646	6.1211%	192,426	82.6455%	2,598,082	FF1 page 227 ln. 8	(1)
	Cash Working Capital									
19	Operation & Maintenance Expense					389,810		5,263,108	W/S 4C, Line 16	(1)
20	Administrative & General Expense					611,174		8,251,915	W/S 4C, Line 19	(3)
21	Transmission Support Expense					357,869			W/S 7	(1)
22	Subtotal (line 19+20+21)					1,358,853		13,515,023		(3)
23						0.125		0.125	x 45 / 360	(1)
24	Total (line 22 * line 23)					169,857		1,689,378		(3)

(a) All items are specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries and Plant Allocation Factors are not used (column 2).
(b) W/S 5A & 5B

(c)				
	Account 190	5,663,481	FF1 page 234 ln. 18, footnote	(1)
	Less Reserve for Disputed Transactions	-	FF1 page 234 ln. 18, footnote	(1)
	Total Account 190	5,663,481		(1)

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Proposed revisions reflect the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset
(3) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Western Massachusetts Electric Company (WMECO)
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements under Changed Rates
Under Attachment F of the ISO-NE OATT
For Costs in 2014
Worksheet 4C

					Pre-1997 PTF		Post-1996 PTF			
		(1)	(2) Wage/Plant Allocation	(3)	(4) PTF Allocation	(5) = (3)*(4) PTF	(6) PTF Allocation	(7) = (3)*(6) Post-96 PTF		
LN.		Transmission	Factors (a)	Transmission	Factor (b)	Allocated	Factor (b)	Allocated	Reference	Notes
	Depreciation Expense									
1	Transmission Depreciation	15,972,687		15,972,687	6.1211%	977,704	82.6455%	13,200,707	FF1 page 336 ln. 7	(1)
2	General Depreciation	789,658		789,658	6.1211%	48,336	82.6455%	652,617	FF1 page 336 ln. 10, footnote	(1)
3	Total (line 1+2)	16,762,345		16,762,345		1,026,040		13,853,324		(1)
4	Amortization of Loss on Reacquired Debt	49,668		49,668	6.1211%	3,040	82.6455%	41,048	FF1 page 114, ln. 64, footnote	(1)
5	Amortization of Investment Tax Credits	35,604		35,604	6.1211%	2,179	82.6455%	29,425	FF1 page 266 ln. 8(f), footnote	(1)
	Property Taxes									
6	Transmission Property Taxes	18,717,332		18,717,332	6.1211%	1,145,707	82.6455%	15,469,033	FF1 page 262 ln. 32i, footnote	(1)
7	General Property Taxes (c)				6.1211%	-	82.6455%	-		(1)
8	Total (line 6+7)	18,717,332		18,717,332		1,145,707		15,469,033		(1)
	Transmission Operation and Maintenance									
9	Operation and Maintenance	20,725,279		20,725,279	6.1211%	1,268,615	82.6455%	17,128,510	FF1 page 321 ln. 112	(1)
10	Transmission of Electricity by Others - #565	13,174,678		13,174,678	6.1211%	806,435	82.6455%	10,888,279	FF1 page 321 ln. 96	(1)
11	Account 561.1	12,368		12,368	6.1211%	757	82.6455%	10,222	FF1 page 321 ln. 85	(1)
12	Account 561.2	50,569		50,569	6.1211%	3,095	82.6455%	41,793	FF1 page 321 ln. 86	(1)
13	Account 561.3	13,262		13,262	6.1211%	812	82.6455%	10,960	FF1 page 321 ln. 87	(1)
14	Account 561.4	1,106,108		1,106,108	6.1211%	67,706	82.6455%	914,148	FF1 page 321 ln. 88	(1)
15	**Station Expenses & Rents	-			6.1211%	-	82.6455%	-	FF1 page 321 ln. 93 + ln. 98	(1)
16	O&M less lines 10 thru 15	6,368,294		6,368,294		389,810		5,263,108		(1)
	Transmission Administrative and General									
17	Administrative and General	8,041,502		8,041,502	6.1211%	492,228	82.6455%	6,645,940	FF1 page 320 ln. 197, footnote	(1)
18	Transmission Merger-Related Costs	1,943,209		1,943,209	6.1211%	118,946	82.6455%	1,605,975	**Exhibit No. ES-220, Page 4 of 8, Line 2(D)**	(2)
19	Total (line 17 + 18)					611,174		8,251,915		(2)
20	*Payroll Tax Expense*	18,291		18,291	6.1211%	1,120	82.6455%	15,117		(1)
	Federal Unemployment	283							FF1 page 262 ln. 3i, footnote	(1)
	FICA	13,202							FF1 page 262 ln. 5i, footnote	(1)
	Medicare	3,757							FF1 page 262 ln. 9i, footnote	(1)
	CT Unemployment	852							FF1 page 262 ln. 13i, footnote	(1)
	DC Unemployment	1							FF1 page 262.1 ln. 6i, footnote	(1)
	FL Unemployment	-							FF1 page 262.1 ln. 10i, footnote	(1)
	GA Unemployment	-							FF1 page 262.1 ln. 14i footnote	(1)
	MA Unemployment	69							FF1 page 262 ln. 22i, footnote	(1)
	MA Universal Health	19							FF1 page 262 ln. 27i, footnote	(1)
	MI Unemployment	-							FF1 page 262.1 ln. 14i footnote	(1)
	NH Unemployment	108							FF1 page 262 ln. 37i, footnote	(1)
	NJ Unemployment	-							FF1 page 262 footnote	(1)
	NY Unemployment	-							FF1 page 262.1, footnote	(1)
	Total	18,291	To Line 19							(1)

** To the extent that PTF Support Payments are reflected in worksheet 7 they will be excluded from this calculation.
(a) All items are specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries and Plant Allocation Factors are not used (column 2).
(b) W/S 5A & 5B
(c) Transmission related general property taxes are included in the Transmission Property tax number footnoted in the FF1.

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Exhibit No. ES-222
Schedule 1

Summary of Impact on NSTAR Electric's PTF Revenue Requirements under Attachment F of ISO-NE OATT (3-year amortization)

Eversource Energy Service Company

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirement Comparison Under Present and Changed Rates
Under Attachment F of the ISO-NE OATT
For the Calendar Years 2016-2018

Line	(A) Description	(B) Total PTF Revenue Requirements Under Present Rates		(C) Total PTF Revenue Requirements Under Changed Rates		(D) = (C) - (B) Difference (5) (Rounded to '000s)	(E) = (D) / (B) % Difference
1	2016 Estimated PTF Revenue Requirements	$ 262,066,250	(1)	$ 266,039,449	(2)	$ 3,973,000	1.5%
2	2017 Estimated PTF Revenue Requirements	$ 262,066,250	(1)	$ 265,648,877	(3)	$ 3,583,000	1.4%
3	2018 Estimated PTF Revenue Requirements	$ 262,066,250	(1)	$ 265,257,811	(4)	$ 3,192,000	1.2%

Notes:

(1) Exhibit No. ES-222, Schedule 2, Page 1 of 5, Line 10(C)
(2) Exhibit No. ES-222, Schedule 3, Page 1 of 5, Line 10(C)
(3) Exhibit No. ES-222, Schedule 4, Page 1 of 5, Line 10(C)
(4) Exhibit No. ES-222, Schedule 5, Page 1 of 5, Line 10(C)
(5) In connection with the three-year amortization alternative (with the proposed effective date of June 1, 2016), Eversource is showing the revenue impact for the thirty-six month period June 1, 2016 through May 31, 2019. Eversource is using calendar year revenue requirement calculations as estimates for the thirty-six month period beginning June 1, 2016. See Cooper Testimony Exhibit No. ES-200.

	2016	2017	2018	2019	Total
The amounts for each year are as follows:	$ 2,318,000	$ 3,746,000	$ 3,355,000	$ 1,330,000	$ 10,749,000

Exhibit No. ES-222
Schedule 2

NSTAR Electric's PTF Revenue Requirements under the Present Rates

Eversource Energy Service Company

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements
Calculated under the Present Rates in Attachment F of the ISO-NE OATT
For the Calendar Year 2016

	(A)	(B)	(C)
Line	**Description**	**Reference**	**NSTAR Electric**
1	2014 Actual PTF Revenue Requirements	Exhibit No. ES-222, Schedule 2, Page 2 of 5, Line 30, Col.D	$ 216,579,241
2	Estimated 2015 PTF Plant Additions	(1)	$ 146,000,000
3	Carrying Charge Factor (CCF)	Exhibit No. ES-222, Schedule 2, Page 2 of 5, Note (3)	13.89%
4	2015 Incremental Estimated PTF Revenue Requirements	Line 2 x 3	$ 20,279,943
5	2015 Incremental Estimated PTF Intangible Plant Rev. Req.	(1)	$ 343,300
6	Total Estimated PTF Revenue Requirement for 2015	Line 1 + 4 + 5	$ 237,202,484
7	Estimated 2016 PTF Plant Additions	(1)	$ 179,000,000
8	Carrying Charge Factor (CCF)	Line 3	13.89%
9	2016 Incremental Estimated PTF Revenue Requirements	Line 7 x 8	$ 24,863,766
10	Total Estimated PTF Revenue Requirement for 2016	Line 6 + 9	$ 262,066,250 (2)

Notes:
(1) Based on Eversource's Forecast
(2) The revenue requirements calculations for the calendar year 2016 (including any forecast for 2016) are used as an estimate for the revenue requirements for 2017 and 2018, which are used to calculate the revenue impact of the proposed cost recovery.

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements
Calculated under the Present Rates in Attachment F of the ISO-NE OATT
For Costs in 2014
Sheet 2a

Line	Investment Base	Attachment F Reference Section:	Pre-1997	Post-1996	Reference	Notes
	Col.A	Col.B	Col.C	Col.D	Col.E	
1	Transmission Plant	II (A)(1)(a)	$ 394,245,298	$ 1,176,211,529	Sheet 4, line 1	(1)
2	General Plant	II (A)(1)(b)	4,064,182	12,125,263	Sheet 4, line 2	(1)
3	Plant Held For Future Use	II (A)(1)(c)	-	13,571,504	Sheet 4, line 4	(1)
4	**Total Plant** (Line 1 + 2 + 3)		398,309,480	1,201,908,296		
5	Accumulated Depreciation	II (A)(1)(d)	(95,102,434)	(283,732,865)	Sheet 4, line 7	(1)
6	Accumulated Deferred Income Taxes	II (A)(1)(e)	(75,011,955)	(223,794,030)	Sheet 4, line 11	(1)
7	Loss On Reacquired Debt	II (A)(1)(f)	757,488	2,259,924	Sheet 4, line 12	(1)
8	Other Regulatory Assets	II (A)(1)(g)	4,930,985	14,711,323	Sheet 4, line 16	(2)
9	**Net Investment** (Line 4 + 5 + 6 + 7 + 8)		233,883,564	711,352,648		(2)
10	Prepayments	II (A)(1)(h)	2,283,784	6,813,544	Sheet 4, line 17	(1)
11	Materials & Supplies	II (A)(1)(II)	5,909,946	17,631,999	Sheet 4, line 18	(1)
12	Cash Working Capital	II (A)(1)(j)	1,019,059	2,974,825	Sheet 4, line 24	(2)
13	**Total Investment Base** (Line 9 + 10 + 11 + 12)		$ 243,096,353	$ 738,773,016		(2)
	Revenue Requirement					
14	Investment Return and Income Taxes	II (A)	$ 30,191,595	$ 93,229,112	Sheet 3a, Line 26	(2)
15	Depreciation Expense	II (B)	8,679,581	25,895,050	Sheet 5, Line 3	(1)
16	Amortization of Loss on Reacquired Debt	II (C)	58,839	175,544	Sheet 5, Line 4	(1)
17	Investment Tax Credit	II (D)	(77,133)	(230,121)	Sheet 5, Line 5	(1)
18	Property Taxes	II (E)	7,099,692	21,181,538	Sheet 5, Line 6	(1)
19	Payroll tax Expense	II (F)	269,960	805,411	Sheet 5, Line 22	(1)
20	Operation & Maintenance Expense	II (G)	4,580,096	13,664,461	Sheet 5, Line 11	(1)
21	Administrative & General Expense	II (H)	3,396,791	10,134,142	Sheet 5, Line 20	(2)
22	Transmission Related Integrated Facilities Charge	II (I)	-	-	N/A	(1)
23	Transmission Support Revenue	II (J)	(1,153,965)	-	Sheet 7, Line 9	(1)
24	Transmission Support Expense	II (K)	1,329,554	-	Sheet 7, Line 9	(1)
25	Transmission Related Expense from Generators	II (L)	-	-	N/A	(1)
26	Transmission Related Taxes and Fees Charge	II (M)	104,168	310,778	Sheet 5, Line 21	(1)
27	Revenue for ST Trans Service Under NEPOOL Tariff	II (N)	(35,083)	(104,467)	Attachment B, Lines 9 & 10	(1)
28	Transmission Rents Received for Electric Property	II (O)	(2,926,302)	-	Attachment C, Line 3	(1)
29	**Total Revenue Requirements** (Sum of Lines 14 through 28)		$ 51,517,793	$ 165,061,448		(2)
30	**Total Pre-1997 and Post 1996** (Line 29 [Pre-1997 + Post-1996])			$ 216,579,241		(2)

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000. Provided this support because these balances will be revised under the changed rates.

(3) Carrying Charge Factor ((Sheet 3a, Line 17 (C) + Sheet 2a, Line 15 thru 21) / Line 1) **13.89%**

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements
Calculated under the Present Rates in Attachment F of the ISO-NE OATT
For Costs in 2014
Sheet 3a

Line	Description	Capitalization 12/31/14	Weighted Capitalization	Weighted Cost of Capital (a)	Weighted Cost of Capital	Equity Portion		Notes
	Col.A	Col.B	Col.C	Col.D	Col.E	Col.F		(1)
1	Long-Term Debt	$ 1,792,712,148	41.74%	4.19%	1.75%		FF1 112.24(c)	(1)
2	Preferred Stock	43,000,000	1.00%	4.56%	0.05%	0.05%	FF1 112.3(c)	(1)
3	Common Equity	2,459,452,736	57.26%	11.07%	6.34%	6.34%	FF1 112.16(c) less Line 3(c)	(1)
4	Total Investment Return	$ 4,295,164,884	100.00%		8.14%	6.39%	Sum of Lines 1 to 3	(1)

ROE per ISO New England Inc. Transmission, Markets and Services Tariff, Section II Attachment F II.A.2.(iii), page 231 http://www.iso-ne.com/regulatory/tariff/sect_2/oatt/sect_ii.pdf

Line	Description	Pre-97	Post-96		Notes
5	**Federal Income Tax (FIT)**				
6	A= Preferred & Equity Return	6.39%	6.39%	Line 4, Col F	(1)
7	B= Transmission Related Amortization of ITC	$ (77,133)	$ (230,121)	Sheet 2a, Line 17	(1)
8	C= Equity AFUDC Component of Depreciation Expense	$ 18,983	$ 56,635	Sheet 10, Column (g)	(1)
9	D= Transmission Investment Base	$ 243,096,353	$ 738,773,016	Sheet 2a, Line 13	(2)
10	FT = Federal Income Tax Rate	35.00%	35.00%	Federal Income Tax Rate	(1)
11	FIT = (A+[C+B)/D])(FT)/(1-FT)	3.42790%	3.42810%	Federal Income Tax	(1)
12	ST = State Income Tax Rate	8.00%	8.00%	State Tax Rate	(1)
13	**State Income Tax (SIT)**				(1)
14	SIT = (A+[(C+B)/D]+Federal Income Tax)(ST)/(1-ST)	0.8517%	0.8517%	State Income Tax	(1)
15	Allowed Return	12.4196%	12.4198%	line 4, Col.E + Line 11 + Line 14	(1)
16	D= Transmission Investment Base	$ 243,096,353	$ 738,773,016	Sheet 2a, Line 13	(2)
17	**Return**	$ 30,191,595	$ 91,754,131	Line 15 * Line 16	(2)
18	Incremental return for Post 2003 PTF Investment				
19	A= Incremental Return		0.6700%	Per Opinion No. 489 and Opinion No. 531-B (b)	(1)
20	Effective Incremental (a')		0.3800%	line 19 * line 3, Col C	(1)
21	Additional FIT (a'/A')		0.2046%	Incremental FIT = (A' x FT)/(1-FT)	(1)
22	Additional SIT (a'/A')		0.0508%	Incremental SIT = (A' + FIT)(ST)/(1-ST)	(1)
23	Additional Return		0.6354%	Sum lines 20 thru 22	(1)
24	Post 2003 PTF net Investment		$ 232,134,198	Sheet 8, line 15	(1)
25	Additional 100 bp Return Post 2003 PTF Investment		$ 1,474,981	Line 23 * Line 24	(1)
26	Total Return	$ 30,191,595	$ 93,229,112	Line 17 + Line 25	(2)

Line	Description	Capitalization 12/31/14	Weighted Capitalization	Weighted Cost of Capital	Weighted Cost of Capital	Equity Portion	Notes
27	**Incremental return for PTF 50 Basis Point Adder**						
28	Long-Term Debt	$ 1,792,712,148	41.74%	4.19%	1.75%		(1)
29	Preferred Stock	43,000,000	1.00%	4.56%	0.05%		(1)
30	Common Equity	2,459,452,736	57.26%	0.50%	0.29%	0.29%	(1)
31	Total Investment Return	$ 4,295,164,884	100.00%		2.09%	0.29%	(1)

Line	Description	Pre-97	Post-96		Notes
32	**Federal Income Tax (FIT)**				
33	A= Incremental Return	0.29%	0.29%	Line 31, Col F	(1)
34	B= Transmission Related Amortization of ITC	$ -	$ -	N/A	(1)
35	C= Equity AFUDC Component of Depreciation Expense	$ -	$ -	N/A	(1)
36	D= Transmission Investment Base	$ 243,096,353	$ 738,773,016	Sheet 2a, Line 13	(2)
37	FT = Federal Income Tax Rate	35.00%	35.00%	Federal Income Tax Rate	(1)
38	FIT = (A+[C+B)/D])(FT)/(1-FT)	0.15620%	0.15620%	Federal Income Tax	(1)
39	ST = State Income Tax Rate	8.00%	8.00%	State Tax Rate	(1)
40	**State Income Tax (SIT)**				(1)
41	SIT = (A+[(C+B)/D]+Federal Income Tax)(ST)/(1-ST)	0.0388%	0.0388%	State Income Tax	(1)
					(1)
42	Allowed Return	0.4850%	0.4850%	line 33 + Line 38 + Line 41	(1)
43	D= Transmission Investment Base	$ 243,096,353	$ 738,773,016	Sheet 2a, Line 13	(2)
44	Return 50 bp Adder	$ 1,179,017	$ 3,583,049	Line 42 * Line 43	(2)
45	Total Return 50 bp Adder		$ 4,762,066	Line 44 Pre-97 + Line 44 Post 96	(2)
46	Total Incremental Return		$ 6,237,047	Line 25 + Line 45	(2)

(a) See Attachment F for weighted cost of debt and preferred stock support.
(b) As a result of Opinion No. 531-B, these projects receive an ROE incentive of 67 bp.

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000. Provided this support because these balances will be revised under the changed rates.

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements
Calculated under the Present Rates in Attachment F of the ISO-NE OATT
For Costs in 2014
Sheet 4

Line	Description	Total	Wage/Plant Allocation Factors		Transmission Allocated	Pre-97 PTF Allocation Factor (a)	Pre-97 PTF Allocated	Post-96 PTF Allocation Factor (a)	Post-96 PTF Allocated	Reference	Notes
	Col.A	Col.B	Col.C		Col.D (Col.B x Col.C)	Col.E	Col.F (Col.D x Col.E)	Col.G	Col.H (Col.D x Col.G)	Col.I	
	Transmission Plant										
1	Transmission Plant (exc SCADA)	$ 1,903,972,438			$ 1,903,972,438		$ 394,245,298		$ 1,176,211,529	Sheet 6, Line 1 (PTF) & Line 2 (Total)	(1)
2	General Plant	$ 186,941,660	10.4993%	(b)	$ 19,627,566	20.7065%	$ 4,064,182	61.7767%	$ 12,125,263	FF1 207.99(g)	(1)
3	Total Transmission Plant (line 1 + 2)				$ 1,923,600,004		$ 398,309,480		$ 1,188,336,792		(1)
4	Transmission Plant Held for Future Use	$ 13,571,504	100.0000%		$ 13,571,504	0.0000%	$ -	100.0000%	$ 13,571,504	FF1 214.14(d) to 18(d)	(1)
	Transmission Accumulated Depreciation										
5	Transmission Accum. Depreciation	$ (453,776,651)	100.0000%		$ (453,776,651)	20.7065%	$ (93,961,262)	61.7767%	$ (280,328,240)	FF1 219.25(b)	(1)
6	General Plant Accum.Depreciation	$ (52,490,917)	10.4993%	(b)	$ (5,511,179)	20.7065%	$ (1,141,172)	61.7767%	$ (3,404,625)	FF1 219.28(b)	(1)
7	Total Transmission Acc Dep (line 5 + 6)				$ (459,287,830)		$ (95,102,434)		$ (283,732,865)		(1)
	Transmission Accumulated Deferred Taxes										
8	Accumulated Deferred Taxes (282) (d)	$ (1,143,462,163)	28.4332%	(c)	$ (325,122,884)	20.7065%	$ (67,321,570)	61.7767%	$ (200,850,189)	FF1 275.9(k) - 275.4(k)	(1)
9	Accumulated Deferred Taxes (283)				$ (45,243,071)	20.7065%	$ (9,368,256)	61.7767%	$ (27,949,676)	Sheet 9, Line 25, Col D	(1)
10	Accumulated Deferred Taxes (190)				$ 8,103,112	20.7065%	$ 1,677,871	61.7767%	$ 5,005,835	Sheet 9, Line 10, Col D	(1)
11	Total ADIT (line 8 + 9 + 10)				$ (362,262,843)		$ (75,011,955)		$ (223,794,030)		(1)
12	Transmission loss on Reacquired Debt	$ 12,865,994	28.4332%	(c)	$ 3,658,214	20.7065%	$ 757,488	61.7767%	$ 2,259,924	FF1 111.81(c)	(1)
	Other Regulatory Assets										
13	FAS 106	$ -	10.4993%	(b)	$ -					FF1 232	(1)
14	ASC 740 Regulatory Asset (FAS 109)	$ 87,768,732	28.4332%	(c)	$ 24,955,459					FF1 232.29(f)	(1)
15	ASC 740 Regulatory Liability (FAS 109)	$ (4,015,556)	28.4332%	(c)	$ (1,141,751)					FF1 278.2(f)	(1)
16	Total (line 13 + 14 + 15)	$ 83,753,176			$ 23,813,708	20.7065%	$ 4,930,985	61.7767%	$ 14,711,323		(2)
17	Transmission Prepayments	$ 105,048,059	10.4993%	(b)	$ 11,029,311	20.7065%	$ 2,283,784	61.7767%	$ 6,813,544	FF1 111.57(c)	(1)
18	Transmission Materials and Supplies	$ 28,541,503	100.0000%		$ 28,541,503	20.7065%	$ 5,909,946	61.7767%	$ 17,631,999	FF1 227.8(c) + 227.5(c) Footnote	(1)
	Cash Working Capital										
19	Operation & Maintenance Expense						$ 4,580,096		$ 13,664,461	Sheet 5, line 11	(1)
20	Administrative & General Expense						$ 3,396,791		$ 10,134,142	Sheet 5, line 20	(2)
21	Net Transmission Support Expense						$ 175,589		$ -	Sheet 7, line 9	(1)
22	Total (line 19 + 20 + 21)						$ 8,152,476		$ 23,798,603		(2)
23	45 day allowance per tariff						0.1250		0.1250	= 45 days / 360 days	(1)
24	Cash Working Capital (line 22 * 23)						$ 1,019,059		$ 2,974,825		(2)

(a) PTF Allocator (Sheet 6, Line 3)
(b) Wages & Salaries Allocator (Sheet 6, Line 13)
(c) Plant Allocator (Sheet 6, Line 18)
(d) ADIT in FERC Account 282 excludes ADIT associated with transition property from FF1 275.4(k)

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000. Provided this support because these balances will be revised under the changed rates.

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements
Calculated under the Present Rates in Attachment F of the ISO-NE OATT
For Costs in 2014
Sheet 5

						Pre-97 PTF		Post-96 PTF			
Line	Description	Total	Wage/Plant Allocation Factors		Transmission Allocated	Allocation Factor (a)	Pre-97 PTF Allocated	Allocation Factor (a)	Post-96 PTF Allocated	Reference	Notes
	Col.A	Col.B	Col.C		Col.D (Col.B x Col.C)	Col.E	Col.F (Col.D x Col.E)	Col.G	Col.H (Col.D x Col.G)	Col.I	
	Depreciation Expense										
1	Transmission Depreciation	$ 41,001,613			$ 41,001,613	20.7065%	$ 8,489,999	61.7767%	$ 25,329,443	FF1 336.7(b)	(1)
2	General Depreciation	$ 8,720,270	10.4993%	(b)	$ 915,567	20.7065%	$ 189,582	61.7767%	$ 565,607	FF1 336.10(b)	(1)
3	Total (line 1 + 2)	$ 49,721,883			$ 41,917,180		$ 8,679,581		$ 25,895,050		
4	Amortization of Loss on Reacquired Debt	$ 999,391	28.4332%	(c)	$ 284,159	20.7065%	$ 58,839	61.7767%	$ 175,544	FF1 117.64(c)	(1)
5	Amortization of Investment Tax Credits	$ 1,310,106	28.4332%	(c)	$ 372,505	20.7065%	$ 77,133	61.7767%	$ 230,121	FF1 114.19(c)	(1)
	Property Taxes										
6	Transmission Property Taxes	$ 120,588,821	28.4332%	(c)	$ 34,287,261	20.7065%	$ 7,099,692	61.7767%	$ 21,181,538	FF1 263.5(i)	(1)
	Transmission Operation and Maintenance										
7	Operation and Maintenance	$ 362,540,896			$ 362,540,896	20.7065%	$ 75,069,531	61.7767%	$ 223,965,802	FF1 321.112(b)	(1)
8	less: Transmission of Electricity by Others (565)	$ 324,980,606			$ 324,980,606	20.7065%	$ 67,292,109	61.7767%	$ 200,762,294	FF1 321.96(b)	(1)
9	less: Load Dispatching (561 to 561.4)	$ 15,426,418			$ 15,426,418	20.7065%	$ 3,194,271	61.7767%	$ 9,529,932	FF1 321.85(b) through 321.88(b)	(1)
10	less: Rents (567)	$ 14,755			$ 14,755	20.7065%	$ 3,055	61.7767%	$ 9,115	FF1 321.98(b)	(1)
11	O&M for RNS Tariff (line 7 - 8 - 9 - 10)	$ 22,119,117			$ 22,119,117		$ 4,580,096		$ 13,664,461		(1)
	Transmission Administrative and General										
12	Administrative and General	$ 145,329,829								FF1 323.197(b)	(1)
13	less: Property Insurance (924)	$ 926,016								FF1 323.185(b)	(1)
14	less: Regulatory Commission Expenses (928)	$ 9,560,209								FF1 323.189(b)	(1)
15	less: Miscellaneous General Expenses (930.2) (d)	$ 52,118								FF1 232.2.14(e)	(1)
16	less: General Advertising Expense (930.1)	$ 32,018								FF1 323.191(b)	(1)
17	Subtotal (line 12 - sum of lines 13 through 16)	$ 134,759,468	10.4993%	(b)	$ 14,148,801	20.7065%	$ 2,929,721	61.7767%	$ 8,740,662		(1)
18	plus: Property Insurance (line 13)	$ 926,016	28.4332%	(c)	$ 263,296	20.7065%	$ 54,519	61.7767%	$ 162,656	FF1 323.185(b)	(1)
19	plus: Regulatory Comm. Exp (T FERC Assessments)	$ 1,992,376	100.0000%		$ 1,992,376	20.7065%	$ 412,551	61.7767%	$ 1,230,824	FF1 350.6(d)	(1)
20	Total A&G for RNS Tariff (Line 17 + 18 + 19)	$ 137,677,860			$ 16,404,473		$ 3,396,791		$ 10,134,142		(2)
21	Transmission Related Taxes and Fees	$ 1,769,295	28.4332%	(c)	$ 503,067	20.7065%	$ 104,168	61.7767%	$ 310,778	FF1 263.8(i)+14(i)+19(i)	(1)
22	Payroll Tax Expense	$ 12,417,455	10.4993%	(b)	$ 1,303,746	20.7065%	$ 269,960	61.7767%	$ 805,411	FF1 263.10(i)+15(i)+18(i)	(1)

(a) PTF Allocator (Sheet 6, Line 3)
(b) Wages & Salaries Allocator (Sheet 6, Line 13)
(c) Plant Allocator (Sheet 6, Line 18)
(d) NSTAR Green Program costs are excludable for Transmission billing purposes.

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
Provided this support because these balances will be revised under the changed rates.

Exhibit No. ES-222
Schedule 3

NSTAR Electric's PTF Revenue Requirements under the Changed Rates for 2016

Eversource Energy Service Company

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements
Calculated under the Present Rates in Attachment F of the ISO-NE OATT
For The Calendar Year 2016

	(A)	(B)	(C)
Line	**Description**	**Reference**	**NSTAR Electric**
1	2014 Actual PTF Revenue Requirements	Exhibit No. ES-222, Schedule 3, Page 2 of 5, Line 30, Col.D	$ 220,552,440
2	Estimated 2015 PTF Plant Additions	(1)	$ 146,000,000
3	Carrying Charge Factor (CCF)	Exhibit No. ES-222, Schedule 2, Page 2 of 5, Note (3)	13.89%
4	2015 Incremental Estimated PTF Revenue Requirements	Line 2 x 3	$ 20,279,943
5	2015 Incremental Estimated PTF Intangible Plant Rev. Req.	(1)	$ 343,300
6	Total Estimated PTF Revenue Requirement for 2015	Line 1 + 4 + 5	$ 241,175,683
7	Estimated 2016 PTF Plant Additions	(1)	$ 179,000,000
8	Carrying Charge Factor (CCF)	Line 3	13.89%
9	2016 Incremental Estimated PTF Revenue Requirements	Line 7 x 8	$ 24,863,766
10	Total Estimated PTF Revenue Requirement for 2016	Line 6 + 9	$ 266,039,449

Notes:
(1) Based on Eversource's Forecast

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements
Calculated under the Present Rates in Attachment F of the ISO-NE OATT
For Costs in 2014
Sheet 2a

Line	Investment Base	Attachment F Reference Section:	Pre-1997	Post-1996	Reference	Notes
	Col.A	Col.B	Col.C	Col.D	Col.E	
1	Transmission Plant	II (A)(1)(a)	$ 394,245,298	$ 1,176,211,529	Sheet 4, line 1	(1)
2	General Plant	II (A)(1)(b)	4,064,182	12,125,263	Sheet 4, line 2	(1)
3	Plant Held For Future Use	II (A)(1)(c)	-	13,571,504	Sheet 4, line 4	(1)
4	**Total Plant** (Line 1 + 2 + 3)		398,309,480	1,201,908,296		
5	Accumulated Depreciation	II (A)(1)(d)	(95,102,434)	(283,732,865)	Sheet 4, line 7	(1)
6	Accumulated Deferred Income Taxes	II (A)(1)(e)	(75,011,955)	(223,794,030)	Sheet 4, line 11	(1)
7	Loss On Reacquired Debt	II (A)(1)(f)	757,488	2,259,924	Sheet 4, line 12	(1)
8	Other Regulatory Assets	II (A)(1)(g)	6,508,902	19,418,948	Sheet 4, line 17	(2)
9	**Net Investment** (Line 4 + 5 + 6 + 7 + 8)		235,461,481	716,060,273		(2)
10	Prepayments	II (A)(1)(h)	2,283,784	6,813,544	Sheet 4, line 18	(1)
11	Materials & Supplies	II (A)(1)(II)	5,909,946	17,631,999	Sheet 4, line 19	(1)
12	Cash Working Capital	II (A)(1)(j)	1,117,679	3,269,052	Sheet 4, line 25	(2)
13	**Total Investment Base** (Line 9 + 10 + 11 + 12)		$ 244,772,890	$ 743,774,868		(2)
	Revenue Requirement					
14	Investment Return and Income Taxes	II (A)	$ 30,400,059	$ 93,851,076	Sheet 3a, Line 26	(2)
15	Depreciation Expense	II (B)	8,679,581	25,895,050	Sheet 5, Line 3	(1)
16	Amortization of Loss on Reacquired Debt	II (C)	58,839	175,544	Sheet 5, Line 4	(1)
17	Investment Tax Credit	II (D)	(77,133)	(230,121)	Sheet 5, Line 5	(1)
18	Property Taxes	II (E)	7,099,692	21,181,538	Sheet 5, Line 6	(1)
19	Payroll tax Expense	II (F)	269,960	805,411	Sheet 5, Line 24	(1)
20	Operation & Maintenance Expense	II (G)	4,580,096	13,664,461	Sheet 5, Line 11	(1)
21	Administrative & General Expense	II (H)	4,185,749	12,487,955	Sheet 5, Line 22	(2)
22	Transmission Related Integrated Facilities Charge	II (I)	-	-	N/A	(1)
23	Transmission Support Revenue	II (J)	(1,153,965)	-	Sheet 7, Line 9	(1)
24	Transmission Support Expense	II (K)	1,329,554	-	Sheet 7, Line 9	(1)
25	Transmission Related Expense from Generators	II (L)	-	-	N/A	(1)
26	Transmission Related Taxes and Fees Charge	II (M)	104,168	310,778	Sheet 5, Line 23	(1)
27	Revenue for ST Trans Service Under NEPOOL Tariff	II (N)	(35,083)	(104,467)	Attachment B, Lines 9 & 10	(1)
28	Transmission Rents Received for Electric Property	II (O)	(2,926,302)	-	Attachment C, Line 3	(1)
29	**Total Revenue Requirements** (Sum of Lines 14 through 28)		$ 52,515,215	$ 168,037,225		(2)
30	**Total Pre-1997 and Post 1996** (Line 29 [Pre-1997 + Post-1996])			$ 220,552,440		(2)

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements
Calculated under the Present Rates in Attachment F of the ISO-NE OATT
For Costs in 2014
Sheet 3a

Line	Description	Capitalization 12/31/14	Weighted Capitalization	Weighted Cost of Capital (a)	Weighted Cost of Capital	Equity Portion		Notes
	Col.A	Col.B	Col.C	Col.D	Col.E	Col.F		
1	Long-Term Debt	$ 1,792,712,148	41.74%	4.19%	1.75%		FF1 112.24(c)	(1)
2	Preferred Stock	43,000,000	1.00%	4.56%	0.05%	0.05%	FF1 112.3(c)	(1)
3	Common Equity	2,459,452,736	57.26%	11.07%	6.34%	6.34%	FF1 112.16(c) less Line 3(c)	(1)
4	Total Investment Return	$ 4,295,164,884	100.00%		8.14%	6.39%	Sum of Lines 1 to 3	(1)

ROE per ISO New England Inc. Transmission, Markets and Services Tariff, Section II Attachment F II.A.2.(iii), page 231 http://www.iso-ne.com/regulatory/tariff/sect_2/oatt/sect_ii.pdf

Line	Description	Pre-97	Post-96		Notes
5	**Federal Income Tax (FIT)**	**Pre-97**	**Post-96**		
6	A= Preferred & Equity Return	6.39%	6.39%	Line 4, Col F	(1)
7	B= Transmission Related Amortization of ITC	$ (77,133)	$ (230,121)	Sheet 2a, Line 17	(1)
8	C= Equity AFUDC Component of Depreciation Expense	$ 18,983	$ 56,635	Sheet 10, Column (g)	(1)
9	D= Transmission Investment Base	$ 244,772,890	$ 743,774,868	Sheet 2a, Line 13	(2)
10	FT = Federal Income Tax Rate	35.00%	35.00%	Federal Income Tax Rate	(1)
11	FIT = (A+[C+B)/D])(FT)/(1-FT)	3.42800%	3.42820%	Federal Income Tax	(1)
12	ST = State Income Tax Rate	8.00%	8.00%	State Tax Rate	(1)
13	**State Income Tax (SIT)**				(1)
14	SIT = (A+[(C+B)/D]+Federal Income Tax)(ST)/(1-ST)	0.8517%	0.8517%	State Income Tax	(1)
15	Allowed Return	12.4197%	12.4199%	line 4, Col.E + Line 11 + Line 14	(1)
16	D= Transmission Investment Base	$ 244,772,890	$ 743,774,868	Sheet 2a, Line 13	(2)
17	**Return**	$ 30,400,059	$ 92,376,095	Line 15 * Line 16	(2)
18	Incremental return for Post 2003 PTF Investment				
19	A= Incremental Return		0.6700%	Per Opinion No. 489 and Opinion No. 531-B (b)	(1)
20	Effective Incremental (a')		0.3800%	line 19 * line 3, Col C	(1)
21	Additional FIT (a'/A')		0.2046%	Incremental FIT = (A' x FT)/(1-FT)	(1)
22	Additional SIT (a'/A')		0.0508%	Incremental SIT = (A' + FIT)(ST)/(1-ST)	(1)
23	Additional Return		0.6354%	Sum lines 20 thru 22	(1)
24	Post 2003 PTF net Investment		$ 232,134,198	Sheet 8, line 15	(1)
25	Additional 100 bp Return Post 2003 PTF Investment		$ 1,474,981	Line 23 * Line 24	(1)
26	Total Return	$ 30,400,059	$ 93,851,076	Line 17 + Line 25	(2)

Line	Description	Capitalization 12/31/14	Weighted Capitalization	Weighted Cost of Capital	Weighted Cost of Capital	Equity Portion	Notes
27	**Incremental return for PTF 50 Basis Point Adder**						
28	Long-Term Debt	$ 1,792,712,148	41.74%	4.19%	1.75%		(1)
29	Preferred Stock	43,000,000	1.00%	4.56%	0.05%		(1)
30	Common Equity	2,459,452,736	57.26%	0.50%	0.29%	0.29%	(1)
31	Total Investment Return	$ 4,295,164,884	100.00%		2.09%	0.29%	(1)

Line	Description	Pre-97	Post-96		Notes
32	**Federal Income Tax (FIT)**	**Pre-97**	**Post-96**		
33	A= Incremental Return	0.29%	0.29%	Line 31, Col F	(1)
34	B= Transmission Related Amortization of ITC	$ -	$ -	N/A	(1)
35	C= Equity AFUDC Component of Depreciation Expense	$ -	$ -	N/A	(1)
36	D= Transmission Investment Base	$ 244,772,890	$ 743,774,868	Sheet 2a, Line 13	(2)
37	FT = Federal Income Tax Rate	35.00%	35.00%	Federal Income Tax Rate	(1)
38	FIT = (A+[C+B)/D])(FT)/(1-FT)	0.15620%	0.15620%	Federal Income Tax	(1)
39	ST = State Income Tax Rate	8.00%	8.00%	State Tax Rate	(1)
40	**State Income Tax (SIT)**				(1)
41	SIT = (A+[(C+B)/D]+Federal Income Tax)(ST)/(1-ST)	0.0388%	0.0388%	State Income Tax	(1)
					(1)
42	Allowed Return	0.4850%	0.4850%	line 33 + Line 38 + Line 41	(1)
43	D= Transmission Investment Base	$ 244,772,890	$ 743,774,868	Sheet 2a, Line 13	(2)
44	Return 50 bp Adder	$ 1,187,149	$ 3,607,308	Line 42 * Line 43	(2)
45	Total Return 50 bp Adder		$ 4,794,457	Line 44 Pre-97 + Line 44 Post 96	(2)
46	Total Incremental Return		$ 6,269,438	Line 25 + Line 45	(2)

(a) See Attachment F for weighted cost of debt and preferred stock support.
(b) As a result of Opinion No. 531-B, these projects receive an ROE incentive of 67 bp.

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements
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For Costs in 2014
Sheet 4

Line	Description	Total	Wage/Plant Allocation Factors	Transmission Allocated	Pre-97 PTF Allocation Factor (a)	Pre-97 PTF Allocated	Post-96 PTF Allocation Factor (a)	Post-96 PTF Allocated	Reference	Notes
	Col.A	Col.B	Col.C	Col.D (Col.B x Col.C)	Col.E	Col.F (Col.D x Col.E)	Col.G	Col.H (Col.D x Col.G)	Col.I	
	Transmission Plant									
1	Transmission Plant (exc SCADA)	$ 1,903,972,438		$ 1,903,972,438		$ 394,245,298		$ 1,176,211,529	Sheet 6, Line 1 (PTF) & Line 2 (Total)	(1)
2	General Plant	$ 186,941,660	10.4993% (b)	$ 19,627,566	20.7065%	$ 4,064,182	61.7767%	$ 12,125,263	FF1 207.99(g)	(1)
3	Total Transmission Plant (line 1 + 2)			$ 1,923,600,004		$ 398,309,480		$ 1,188,336,792		(1)
4	Transmission Plant Held for Future Use	$ 13,571,504	100.0000%	$ 13,571,504	0.0000%	$ -	100.0000%	$ 13,571,504	FF1 214.14(d) to 18(d)	(1)
	Transmission Accumulated Depreciation									
5	Transmission Accum. Depreciation	$ (453,776,651)	100.0000%	$ (453,776,651)	20.7065%	$ (93,961,262)	61.7767%	$ (280,328,240)	FF1 219.25(b)	(1)
6	General Plant Accum.Depreciation	$ (52,490,917)	10.4993% (b)	$ (5,511,179)	20.7065%	$ (1,141,172)	61.7767%	$ (3,404,625)	FF1 219.28(b)	(1)
7	Total Transmission Acc Dep (line 5 + 6)			$ (459,287,830)		$ (95,102,434)		$ (283,732,865)		(1)
	Transmission Accumulated Deferred Taxes									
8	Accumulated Deferred Taxes (282) (d)	$ (1,143,462,163)	28.4332% (c)	$ (325,122,884)	20.7065%	$ (67,321,570)	61.7767%	$ (200,850,189)	FF1 275.9(k) - 275.4(k)	(1)
9	Accumulated Deferred Taxes (283)			$ (45,243,071)	20.7065%	$ (9,368,256)	61.7767%	$ (27,949,676)	Sheet 9, Line 25, Col D	(1)
10	Accumulated Deferred Taxes (190)			$ 8,103,112	20.7065%	$ 1,677,871	61.7767%	$ 5,005,835	Sheet 9, Line 10, Col D	(1)
11	Total ADIT (line 8 + 9 + 10)			$ (362,262,843)		$ (75,011,955)		$ (223,794,030)		(1)
12	Transmission loss on Reacquired Debt	$ 12,865,994	28.4332% (c)	$ 3,658,214	20.7065%	$ 757,488	61.7767%	$ 2,259,924	FF1 111.81(c)	(1)
	Other Regulatory Assets									
13	Unamortized Balance of Transmission Merger-Related Costs	$ 7,620,390	100.0000%	$ 7,620,390					**Exhibit No. ES-220, Page 2 of 8, Line 3(B)**	(2)
14	FAS 106	$ -	10.4993% (b)	$ -					FF1 232	(1)
15	ASC 740 Regulatory Asset (FAS 109)	$ 87,768,732	28.4332% (c)	$ 24,955,459					FF1 232.29(f)	(1)
16	ASC 740 Regulatory Liability (FAS 109)	$ (4,015,556)	28.4332% (c)	$ (1,141,751)					FF1 278.2(f)	(1)
17	Total (line 13 + 14 + 15)	$ 91,373,566		$ 31,434,098	20.7065%	$ 6,508,902	61.7767%	$ 19,418,948		(2)
18	Transmission Prepayments	$ 105,048,059	10.4993% (b)	$ 11,029,311	20.7065%	$ 2,283,784	61.7767%	$ 6,813,544	FF1 111.57(c)	(1)
19	Transmission Materials and Supplies	$ 28,541,503	100.0000%	$ 28,541,503	20.7065%	$ 5,909,946	61.7767%	$ 17,631,999	FF1 227.8(c) + 227.5(c) Footnote	(1)
	Cash Working Capital									
20	Operation & Maintenance Expense					$ 4,580,096		$ 13,664,461	Sheet 5, line 11	
21	Administrative & General Expense					$ 4,185,749		$ 12,487,955	Sheet 5, line 22	(3)
22	Net Transmission Support Expense					$ 175,589		$ -	Sheet 7, line 9	(1)
23	Total (line 19 + 20 + 21)					$ 8,941,434		$ 26,152,416		(3)
24	45 day allowance per tariff					0.1250		0.1250	= 45 days / 360 days	(1)
25	Cash Working Capital (line 22 * 23)					$ 1,117,679		$ 3,269,052		(3)

(a) PTF Allocator (Sheet 6, Line 3)
(b) Wages & Salaries Allocator (Sheet 6, Line 13)
(c) Plant Allocator (Sheet 6, Line 18)
(d) ADIT in FERC Account 282 excludes ADIT associated with transition property from FF1 275.4(k)

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Proposed revisions reflect the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset
(3) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements
Calculated under the Present Rates in Attachment F of the ISO-NE OATT
For Costs in 2014
Sheet 5

Line	Description	Total	Wage/Plant Allocation Factors		Transmission Allocated	Pre-97 PTF Allocation Factor (a)	Pre-97 PTF Allocated	Post-96 PTF Allocation Factor (a)	Post-96 PTF Allocated	Reference	Notes
	Col.A	Col.B	Col.C		Col.D (Col.B x Col.C)	Col.E	Col.F (Col.D x Col.E)	Col.G	Col.H (Col.D x Col.G)	Col.I	
	Depreciation Expense										
1	Transmission Depreciation	$ 41,001,613			$ 41,001,613	20.7065%	$ 8,489,999	61.7767%	$ 25,329,443	FF1 336.7(b)	(1)
2	General Depreciation	$ 8,720,270	10.4993%	(b)	$ 915,567	20.7065%	$ 189,582	61.7767%	$ 565,607	FF1 336.10(b)	(1)
3	Total (line 1 + 2)	$ 49,721,883			$ 41,917,180		$ 8,679,581		$ 25,895,050		(1)
4	Amortization of Loss on Reacquired Debt	$ 999,391	28.4332%	(c)	$ 284,159	20.7065%	$ 58,839	61.7767%	$ 175,544	FF1 117.64(c)	(1)
5	Amortization of Investment Tax Credits	$ 1,310,106	28.4332%	(c)	$ 372,505	20.7065%	$ 77,133	61.7767%	$ 230,121	FF1 114.19(c)	(1)
	Property Taxes										
6	Transmission Property Taxes	$ 120,588,821	28.4332%	(c)	$ 34,287,261	20.7065%	$ 7,099,692	61.7767%	$ 21,181,538	FF1 263.5(i)	(1)
	Transmission Operation and Maintenance										
7	Operation and Maintenance	$ 362,540,896			$ 362,540,896	20.7065%	$ 75,069,531	61.7767%	$ 223,965,802	FF1 321.112(b)	(1)
8	less: Transmission of Electricity by Others (565)	$ 324,980,606			$ 324,980,606	20.7065%	$ 67,292,109	61.7767%	$ 200,762,294	FF1 321.96(b)	(1)
9	less: Load Dispatching (561 to 561.4)	$ 15,426,418			$ 15,426,418	20.7065%	$ 3,194,271	61.7767%	$ 9,529,932	FF1 321.85(b) through 321.88(b)	(1)
10	less: Rents (567)	$ 14,755			$ 14,755	20.7065%	$ 3,055	61.7767%	$ 9,115	FF1 321.98(b)	(1)
11	O&M for RNS Tariff (line 7 - 8 - 9 - 10)	$ 22,119,117			$ 22,119,117		$ 4,580,096		$ 13,664,461		(1)
	Transmission Administrative and General										
12	Administrative and General	$ 145,329,829								FF1 323.197(b)	(1)
13	less: Property Insurance (924)	$ 926,016								FF1 323.185(b)	(1)
14	less: Regulatory Commission Expenses (928)	$ 9,560,209								FF1 323.189(b)	(1)
15	less: Miscellaneous General Expenses (930.2) (d)	$ 52,118								FF1 232.2.14(e)	(1)
16	less: General Advertising Expense (930.1)	$ 32,018								FF1 323.191(b)	(1)
17	less: Merger-Related Costs	$ -									(2)
18	Subtotal (line 12 - sum of lines 13 through 16)	$ 134,759,468	10.4993%	(b)	$ 14,148,801	20.7065%	$ 2,929,721	61.7767%	$ 8,740,662		(1)
19	plus: Property Insurance (line 13)	$ 926,016	28.4332%	(c)	$ 263,296	20.7065%	$ 54,519	61.7767%	$ 162,656	FF1 323.185(b)	(1)
20	plus: Regulatory Comm. Exp (T FERC Assessments)	$ 1,992,376	100.0000%		$ 1,992,376	20.7065%	$ 412,551	61.7767%	$ 1,230,824	FF1 350.6(d)	(1)
21	plus: Transmission Merger-Related Costs	$ 3,810,195	100.0000%		$ 3,810,195	20.7065%	$ 788,958	61.7767%	$ 2,353,813	**Exhibit No. ES-220, Page 2 of 8, Line 2(B)**	(2)
22	Total A&G for RNS Tariff (Line 17 + 18 + 19)	$ 141,488,055			$ 20,214,668		$ 4,185,749		$ 12,487,955		(2)
23	Transmission Related Taxes and Fees	$ 1,769,295	28.4332%	(c)	$ 503,067	20.7065%	$ 104,168	61.7767%	$ 310,778	FF1 263.8(i)+14(i)+19(i)	(1)
24	Payroll Tax Expense	$ 12,417,455	10.4993%	(b)	$ 1,303,746	20.7065%	$ 269,960	61.7767%	$ 805,411	FF1 263.10(i)+15(i)+18(i)	(1)

(a) PTF Allocator (Sheet 6, Line 3)
(b) Wages & Salaries Allocator (Sheet 6, Line 13)
(c) Plant Allocator (Sheet 6, Line 18)
(d) NSTAR Green Program costs are excludable for Transmission billing purposes.

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Exhibit No. ES-222
Schedule 4

NSTAR Electric's PTF Revenue Requirements under the Changed Rates for 2017

Eversource Energy Service Company

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements
Calculated under the Present Rates in Attachment F of the ISO-NE OATT
For The Calendar Year 2017

	(A)	(B)	(C)	
Line	**Description**	**Reference**	**NSTAR Electric**	
1	2014 Actual PTF Revenue Requirements	Exhibit No. ES-222, Schedule 4, Page 2 of 5, Line 30, Col.D	$ 220,161,868	
2	Estimated 2015 PTF Plant Additions	(1)	$ 146,000,000	
3	Carrying Charge Factor (CCF)	Exhibit No. ES-222, Schedule 2, Page 2 of 5, Note (3)	13.89%	
4	2015 Incremental Estimated PTF Revenue Requirements	Line 2 x 3	$ 20,279,943	
5	2015 Incremental Estimated PTF Intangible Plant Rev. Req.	(1)	$ 343,300	
6	Total Estimated PTF Revenue Requirement for 2015	Line 1 + 4 + 5	$ 240,785,111	
7	Estimated 2016 PTF Plant Additions	(1)	$ 179,000,000	
8	Carrying Charge Factor (CCF)	Line 3	13.89%	
9	2016 Incremental Estimated PTF Revenue Requirements	Line 7 x 8	$ 24,863,766	
10	Total Estimated PTF Revenue Requirement for 2016	Line 6 + 9	$ 265,648,877	(2)

Notes:
(1) Based on Eversource's Forecast
(2) The revenue requirements calculations for the calendar year 2016 (including any forecast for 2016) are used as an estimate for the revenue requirements for 2017, which are used to calculate the revenue impact of the proposed cost recovery.

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements
Calculated under the Present Rates in Attachment F of the ISO-NE OATT
For Costs in 2014
Sheet 2a

Line	Investment Base	Attachment F Reference Section:	Pre-1997	Post-1996	Reference	Notes
	Col.A	Col.B	Col.C	Col.D	Col.E	
1	Transmission Plant	II (A)(1)(a)	$ 394,245,298	$ 1,176,211,529	Sheet 4, line 1	(1)
2	General Plant	II (A)(1)(b)	4,064,182	12,125,263	Sheet 4, line 2	(1)
3	Plant Held For Future Use	II (A)(1)(c)	-	13,571,504	Sheet 4, line 4	(1)
4	**Total Plant** (Line 1 + 2 + 3)		398,309,480	1,201,908,296		
5	Accumulated Depreciation	II (A)(1)(d)	(95,102,434)	(283,732,865)	Sheet 4, line 7	(1)
6	Accumulated Deferred Income Taxes	II (A)(1)(e)	(75,011,955)	(223,794,030)	Sheet 4, line 11	(1)
7	Loss On Reacquired Debt	II (A)(1)(f)	757,488	2,259,924	Sheet 4, line 12	(1)
8	Other Regulatory Assets	II (A)(1)(g)	5,719,943	17,065,136	Sheet 4, line 17	(2)
9	**Net Investment** (Line 4 + 5 + 6 + 7 + 8)		234,672,522	713,706,461		(2)
10	Prepayments	II (A)(1)(h)	2,283,784	6,813,544	Sheet 4, line 18	(1)
11	Materials & Supplies	II (A)(1)(II)	5,909,946	17,631,999	Sheet 4, line 19	(1)
12	Cash Working Capital	II (A)(1)(j)	1,117,679	3,269,052	Sheet 4, line 25	(2)
13	**Total Investment Base** (Line 9 + 10 + 11 + 12)		$ 243,983,931	$ 741,421,056		(2)
	Revenue Requirement					
14	Investment Return and Income Taxes	II (A)	$ 30,301,828	$ 93,558,735	Sheet 3a, Line 26	(2)
15	Depreciation Expense	II (B)	8,679,581	25,895,050	Sheet 5, Line 3	(1)
16	Amortization of Loss on Reacquired Debt	II (C)	58,839	175,544	Sheet 5, Line 4	(1)
17	Investment Tax Credit	II (D)	(77,133)	(230,121)	Sheet 5, Line 5	(1)
18	Property Taxes	II (E)	7,099,692	21,181,538	Sheet 5, Line 6	(1)
19	Payroll tax Expense	II (F)	269,960	805,411	Sheet 5, Line 24	(1)
20	Operation & Maintenance Expense	II (G)	4,580,096	13,664,461	Sheet 5, Line 11	(1)
21	Administrative & General Expense	II (H)	4,185,749	12,487,955	Sheet 5, Line 22	(2)
22	Transmission Related Integrated Facilities Charge	II (I)	-	-	N/A	(1)
23	Transmission Support Revenue	II (J)	(1,153,965)	-	Sheet 7, Line 9	(1)
24	Transmission Support Expense	II (K)	1,329,554	-	Sheet 7, Line 9	(1)
25	Transmission Related Expense from Generators	II (L)	-	-	N/A	(1)
26	Transmission Related Taxes and Fees Charge	II (M)	104,168	310,778	Sheet 5, Line 23	(1)
27	Revenue for ST Trans Service Under NEPOOL Tariff	II (N)	(35,083)	(104,467)	Attachment B, Lines 9 & 10	(1)
28	Transmission Rents Received for Electric Property	II (O)	(2,926,302)	-	Attachment C, Line 3	(1)
29	**Total Revenue Requirements** (Sum of Lines 14 through 28)		$ 52,416,984	$ 167,744,884		(2)
30	**Total Pre-1997 and Post 1996** (Line 29 [Pre-1997 + Post-1996])			$ 220,161,868		(2)

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements
Calculated under the Present Rates in Attachment F of the ISO-NE OATT
For Costs in 2014
Sheet 3a

Line	Description	Capitalization 12/31/14	Weighted Capitalization	Weighted Cost of Capital (a)	Weighted Cost of Capital	Equity Portion		Notes
	Col.A	Col.B	Col.C	Col.D	Col.E	Col.F		
1	Long-Term Debt	$ 1,792,712,148	41.74%	4.19%	1.75%		FF1 112.24(c)	(1)
2	Preferred Stock	43,000,000	1.00%	4.56%	0.05%	0.05%	FF1 112.3(c)	(1)
3	Common Equity	2,459,452,736	57.26%	11.07%	6.34%	6.34%	FF1 112.16(c) less Line 3(c)	(1)
4	Total Investment Return	$ 4,295,164,884	100.00%		8.14%	6.39%	Sum of Lines 1 to 3	(1)

ROE per ISO New England Inc. Transmission, Markets and Services Tariff, Section II Attachment F II.A.2.(iii), page 231 http://www.iso-ne.com/regulatory/tariff/sect_2/oatt/sect_ii.pdf

Line	Description	Pre-97	Post-96		Notes
5	**Federal Income Tax (FIT)**				
6	A= Preferred & Equity Return	6.39%	6.39%	Line 4, Col F	(1)
7	B= Transmission Related Amortization of ITC	$ (77,133)	$ (230,121)	Sheet 2a, Line 17	(1)
8	C= Equity AFUDC Component of Depreciation Expense	$ 18,983	$ 56,635	Sheet 10, Column (g)	(1)
9	D= Transmission Investment Base	$ 243,983,931	$ 741,421,056	Sheet 2a, Line 13	(2)
10	FT = Federal Income Tax Rate	35.00%	35.00%	Federal Income Tax Rate	(1)
11	FIT = (A+[C+B)/D])(FT)/(1-FT)	3.42790%	3.42820%	Federal Income Tax	(1)
12	ST = State Income Tax Rate	8.00%	8.00%	State Tax Rate	(1)
13	**State Income Tax (SIT)**				(1)
14	SIT = (A+[(C+B)/D]+Federal Income Tax)(ST)/(1-ST)	0.8517%	0.8517%	State Income Tax	(1)
15	Allowed Return	12.4196%	12.4199%	line 4, Col.E + Line 11 + Line 14	(1)
16	D= Transmission Investment Base	$ 243,983,931	$ 741,421,056	Sheet 2a, Line 13	(2)
17	**Return**	$ 30,301,828	$ 92,083,754	Line 15 * Line 16	(2)
18	Incremental return for Post 2003 PTF Investment				
19	A= Incremental Return		0.6700%	Per Opinion No. 489 and Opinion No. 531-B (b)	(1)
20	Effective Incremental (a')		0.3800%	line 19 * line 3, Col C	(1)
21	Additional FIT (a'/A')		0.2046%	Incremental FIT = (A' x FT)/(1-FT)	(1)
22	Additional SIT (a'/A')		0.0508%	Incremental SIT = (A' + FIT)(ST)/(1-ST)	(1)
23	Additional Return		0.6354%	Sum lines 20 thru 22	(1)
24	Post 2003 PTF net Investment		$ 232,134,198	Sheet 8, line 15	(1)
25	Additional 100 bp Return Post 2003 PTF Investment		$ 1,474,981	Line 23 * Line 24	(1)
26	Total Return	$ 30,301,828	$ 93,558,735	Line 17 + Line 25	(2)

Line	Description	Capitalization 12/31/14	Weighted Capitalization	Weighted Cost of Capital	Weighted Cost of Capital	Equity Portion	Notes
27	**Incremental return for PTF 50 Basis Point Adder**						
28	Long-Term Debt	$ 1,792,712,148	41.74%	4.19%	1.75%		(1)
29	Preferred Stock	43,000,000	1.00%	4.56%	0.05%		(1)
30	Common Equity	2,459,452,736	57.26%	0.50%	0.29%	0.29%	(1)
31	Total Investment Return	$ 4,295,164,884	100.00%		2.09%	0.29%	(1)

Line	Description	Pre-97	Post-96		Notes
32	**Federal Income Tax (FIT)**				
33	A= Incremental Return	0.29%	0.29%	Line 31, Col F	(1)
34	B= Transmission Related Amortization of ITC	$ -	$ -	N/A	(1)
35	C= Equity AFUDC Component of Depreciation Expense	$ -	$ -	N/A	(1)
36	D= Transmission Investment Base	$ 243,983,931	$ 741,421,056	Sheet 2a, Line 13	(2)
37	FT = Federal Income Tax Rate	35.00%	35.00%	Federal Income Tax Rate	(1)
38	FIT = (A+[C+B)/D])(FT)/(1-FT)	0.15620%	0.15620%	Federal Income Tax	(1)
39	ST = State Income Tax Rate	8.00%	8.00%	State Tax Rate	(1)
40	**State Income Tax (SIT)**				(1)
41	SIT = (A+[(C+B)/D]+Federal Income Tax)(ST)/(1-ST)	0.0388%	0.0388%	State Income Tax	(1)
					(1)
42	Allowed Return	0.4850%	0.4850%	line 33 + Line 38 + Line 41	(1)
43	D= Transmission Investment Base	$ 243,983,931	$ 741,421,056	Sheet 2a, Line 13	(2)
44	Return 50 bp Adder	$ 1,183,322	$ 3,595,892	Line 42 * Line 43	(2)
45	Total Return 50 bp Adder		$ 4,779,214	Line 44 Pre-97 + Line 44 Post 96	(2)
46	Total Incremental Return		$ 6,254,195	Line 25 + Line 45	(2)

(a) See Attachment F for weighted cost of debt and preferred stock support.
(b) As a result of Opinion No. 531-B, these projects receive an ROE incentive of 67 bp.

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements
Calculated under the Present Rates in Attachment F of the ISO-NE OATT
For Costs in 2014
Sheet 4

Line	Description	Total	Wage/Plant Allocation Factors	Transmission Allocated	Pre-97 PTF Allocation Factor (a)	Pre-97 PTF Allocated	Post-96 PTF Allocation Factor (a)	Post-96 PTF Allocated	Reference	Notes
	Col.A	Col.B	Col.C	Col.D (Col.B x Col.C)	Col.E	Col.F (Col.D x Col.E)	Col.G	Col.H (Col.D x Col.G)	Col.I	
	Transmission Plant									
1	Transmission Plant (exc SCADA)	$ 1,903,972,438		$ 1,903,972,438		$ 394,245,298		$ 1,176,211,529	Sheet 6, Line 1 (PTF) & Line 2 (Total)	(1)
2	General Plant	$ 186,941,660	10.4993% (b)	$ 19,627,566	20.7065%	$ 4,064,182	61.7767%	$ 12,125,263	FF1 207.99(g)	(1)
3	Total Transmission Plant (line 1 + 2)			$ 1,923,600,004		$ 398,309,480		$ 1,188,336,792		(1)
4	Transmission Plant Held for Future Use	$ 13,571,504	100.0000%	$ 13,571,504	0.0000%	$ -	100.0000%	$ 13,571,504	FF1 214.14(d) to 18(d)	(1)
	Transmission Accumulated Depreciation									
5	Transmission Accum. Depreciation	$ (453,776,651)	100.0000%	$ (453,776,651)	20.7065%	$ (93,961,262)	61.7767%	$ (280,328,240)	FF1 219.25(b)	(1)
6	General Plant Accum.Depreciation	$ (52,490,917)	10.4993% (b)	$ (5,511,179)	20.7065%	$ (1,141,172)	61.7767%	$ (3,404,625)	FF1 219.28(b)	(1)
7	Total Transmission Acc Dep (line 5 + 6)			$ (459,287,830)		$ (95,102,434)		$ (283,732,865)		(1)
	Transmission Accumulated Deferred Taxes									
8	Accumulated Deferred Taxes (282) (d)	$ (1,143,462,163)	28.4332% (c)	$ (325,122,884)	20.7065%	$ (67,321,570)	61.7767%	$ (200,850,189)	FF1 275.9(k) - 275.4(k)	(1)
9	Accumulated Deferred Taxes (283)			$ (45,243,071)	20.7065%	$ (9,368,256)	61.7767%	$ (27,949,676)	Sheet 9, Line 25, Col D	(1)
10	Accumulated Deferred Taxes (190)			$ 8,103,112	20.7065%	$ 1,677,871	61.7767%	$ 5,005,835	Sheet 9, Line 10, Col D	(1)
11	Total ADIT (line 8 + 9 + 10)			$ (362,262,843)		$ (75,011,955)		$ (223,794,030)		(1)
12	Transmission loss on Reacquired Debt	$ 12,865,994	28.4332% (c)	$ 3,658,214	20.7065%	$ 757,488	61.7767%	$ 2,259,924	FF1 111.81(c)	(1)
	Other Regulatory Assets									
13	Unamortized Balance of Transmission Merger-Related Costs	$ 3,810,195	100.0000%	$ 3,810,195					**Exhibit No. ES-220, Page 2 of 8, Line 3(C)**	(2)
14	FAS 106	$ -	10.4993% (b)	$ -					FF1 232	(1)
15	ASC 740 Regulatory Asset (FAS 109)	$ 87,768,732	28.4332% (c)	$ 24,955,459					FF1 232.29(f)	(1)
16	ASC 740 Regulatory Liability (FAS 109)	$ (4,015,556)	28.4332% (c)	$ (1,141,751)					FF1 278.2(f)	(1)
17	Total (line 13 + 14 + 15)	$ 87,563,371		$ 27,623,903	20.7065%	$ 5,719,943	61.7767%	$ 17,065,136		(2)
18	Transmission Prepayments	$ 105,048,059	10.4993% (b)	$ 11,029,311	20.7065%	$ 2,283,784	61.7767%	$ 6,813,544	FF1 111.57(c)	(1)
19	Transmission Materials and Supplies	$ 28,541,503	100.0000%	$ 28,541,503	20.7065%	$ 5,909,946	61.7767%	$ 17,631,999	FF1 227.8(c) + 227.5(c) Footnote	(1)
	Cash Working Capital									
20	Operation & Maintenance Expense					$ 4,580,096		$ 13,664,461	Sheet 5, line 11	
21	Administrative & General Expense					$ 4,185,749		$ 12,487,955	Sheet 5, line 22	(3)
22	Net Transmission Support Expense					$ 175,589		$ -	Sheet 7, line 9	(1)
23	Total (line 19 + 20 + 21)					$ 8,941,434		$ 26,152,416		(3)
24	45 day allowance per tariff					0.1250		0.1250	= 45 days / 360 days	(1)
25	Cash Working Capital (line 22 * 23)					$ 1,117,679		$ 3,269,052		(3)

(a) PTF Allocator (Sheet 6, Line 3)
(b) Wages & Salaries Allocator (Sheet 6, Line 13)
(c) Plant Allocator (Sheet 6, Line 18)
(d) ADIT in FERC Account 282 excludes ADIT associated with transition property from FF1 275.4(k)

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Proposed revisions reflect the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset
(3) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements
Calculated under the Present Rates in Attachment F of the ISO-NE OATT
For Costs in 2014
Sheet 5

Line	Description	Total	Wage/Plant Allocation Factors	Transmission Allocated	Pre-97 PTF Allocation Factor (a)	Pre-97 PTF Allocated	Post-96 PTF Allocation Factor (a)	Post-96 PTF Allocated	Reference	Notes
	Col.A	Col.B	Col.C	Col.D (Col.B x Col.C)	Col.E	Col.F (Col.D x Col.E)	Col.G	Col.H (Col.D x Col.G)	Col.I	
	Depreciation Expense									
1	Transmission Depreciation	$ 41,001,613		$ 41,001,613	20.7065%	$ 8,489,999	61.7767%	$ 25,329,443	FF1 336.7(b)	(1)
2	General Depreciation	$ 8,720,270	10.4993% (b)	$ 915,567	20.7065%	$ 189,582	61.7767%	$ 565,607	FF1 336.10(b)	(1)
3	Total (line 1 + 2)	$ 49,721,883		$ 41,917,180		$ 8,679,581		$ 25,895,050		(1)
4	Amortization of Loss on Reacquired Debt	$ 999,391	28.4332% (c)	$ 284,159	20.7065%	$ 58,839	61.7767%	$ 175,544	FF1 117.64(c)	(1)
5	Amortization of Investment Tax Credits	$ 1,310,106	28.4332% (c)	$ 372,505	20.7065%	$ 77,133	61.7767%	$ 230,121	FF1 114.19(c)	(1)
	Property Taxes									
6	Transmission Property Taxes	$ 120,588,821	28.4332% (c)	$ 34,287,261	20.7065%	$ 7,099,692	61.7767%	$ 21,181,538	FF1 263.5(i)	(1)
	Transmission Operation and Maintenance									
7	Operation and Maintenance	$ 362,540,896		$ 362,540,896	20.7065%	$ 75,069,531	61.7767%	$ 223,965,802	FF1 321.112(b)	(1)
8	less: Transmission of Electricity by Others (565)	$ 324,980,606		$ 324,980,606	20.7065%	$ 67,292,109	61.7767%	$ 200,762,294	FF1 321.96(b)	(1)
9	less: Load Dispatching (561 to 561.4)	$ 15,426,418		$ 15,426,418	20.7065%	$ 3,194,271	61.7767%	$ 9,529,932	FF1 321.85(b) through 321.88(b)	(1)
10	less: Rents (567)	$ 14,755		$ 14,755	20.7065%	$ 3,055	61.7767%	$ 9,115	FF1 321.98(b)	(1)
11	O&M for RNS Tariff (line 7 - 8 - 9 - 10)	$ 22,119,117		$ 22,119,117		$ 4,580,096		$ 13,664,461		
	Transmission Administrative and General									
12	Administrative and General	$ 145,329,829							FF1 323.197(b)	(1)
13	less: Property Insurance (924)	$ 926,016							FF1 323.185(b)	(1)
14	less: Regulatory Commission Expenses (928)	$ 9,560,209							FF1 323.189(b)	(1)
15	less: Miscellaneous General Expenses (930.2) (d)	$ 52,118							FF1 232.2.14(e)	(1)
16	less: General Advertising Expense (930.1)	$ 32,018							FF1 323.191(b)	(1)
17	less: Merger-Related Costs	$ -								(2)
18	Subtotal (line 12 - sum of lines 13 through 16)	$ 134,759,468	10.4993% (b)	$ 14,148,801	20.7065%	$ 2,929,721	61.7767%	$ 8,740,662		(1)
19	plus: Property Insurance (line 13)	$ 926,016	28.4332% (c)	$ 263,296	20.7065%	$ 54,519	61.7767%	$ 162,656	FF1 323.185(b)	(1)
20	plus: Regulatory Comm. Exp (T FERC Assessments)	$ 1,992,376	100.0000%	$ 1,992,376	20.7065%	$ 412,551	61.7767%	$ 1,230,824	FF1 350.6(d)	(1)
21	plus: Transmission Merger-Related Costs	$ 3,810,195	100.0000%	$ 3,810,195	20.7065%	$ 788,958	61.7767%	$ 2,353,813	**Exhibit No. ES-220, Page 2 of 8, Line 2(C)**	(2)
22	Total A&G for RNS Tariff (Line 17 + 18 + 19)	$ 141,488,055		$ 20,214,668		$ 4,185,749		$ 12,487,955		(2)
23	Transmission Related Taxes and Fees	$ 1,769,295	28.4332% (c)	$ 503,067	20.7065%	$ 104,168	61.7767%	$ 310,778	FF1 263.8(i)+14(i)+19(i)	(1)
24	Payroll Tax Expense	$ 12,417,455	10.4993% (b)	$ 1,303,746	20.7065%	$ 269,960	61.7767%	$ 805,411	FF1 263.10(i)+15(i)+18(i)	(1)

(a) PTF Allocator (Sheet 6, Line 3)
(b) Wages & Salaries Allocator (Sheet 6, Line 13)
(c) Plant Allocator (Sheet 6, Line 18)
(d) NSTAR Green Program costs are excludable for Transmission billing purposes.

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Exhibit No. ES-222
Schedule 5

NSTAR Electric's PTF Revenue Requirements under the Changed Rates for 2018

Eversource Energy Service Company

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements
Calculated under the Present Rates in Attachment F of the ISO-NE OATT
For The Calendar Year 2018

	(A)	(B)	(C)	
Line	**Description**	**Reference**	**NSTAR Electric**	
1	2014 Actual PTF Revenue Requirements	Exhibit No. ES-222, Schedule 5, Page 2 of 5, Line 30, Col.D	$ 219,770,802	
2	Estimated 2015 PTF Plant Additions	(1)	$ 146,000,000	
3	Carrying Charge Factor (CCF)	Exhibit No. ES-222, Schedule 2, Page 2 of 5, Note (3)	13.89%	
4	2015 Incremental Estimated PTF Revenue Requirements	Line 2 x 3	$ 20,279,943	
5	2015 Incremental Estimated PTF Intangible Plant Rev. Req.	(1)	$ 343,300	
6	Total Estimated PTF Revenue Requirement for 2015	Line 1 + 4 + 5	$ 240,394,045	
7	Estimated 2016 PTF Plant Additions	(1)	$ 179,000,000	
8	Carrying Charge Factor (CCF)	Line 3	13.89%	
9	2016 Incremental Estimated PTF Revenue Requirements	Line 7 x 8	$ 24,863,766	
10	Total Estimated PTF Revenue Requirement for 2016	Line 6 + 9	$ 265,257,811	(2)

Notes:
(1) Based on Eversource's Forecast
(2) The revenue requirements calculations for the calendar year 2016 (including any forecast for 2016) are used as an estimate for the revenue requirements for 2018, which are used to calculate the revenue impact of the proposed cost recovery.

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements
Calculated under the Present Rates in Attachment F of the ISO-NE OATT
For Costs in 2014
Sheet 2a

Line	Investment Base	Attachment F Reference Section:	Pre-1997	Post-1996	Reference	Notes
	Col.A	Col.B	Col.C	Col.D	Col.E	
1	Transmission Plant	II (A)(1)(a)	$ 394,245,298	$ 1,176,211,529	Sheet 4, line 1	(1)
2	General Plant	II (A)(1)(b)	4,064,182	12,125,263	Sheet 4, line 2	(1)
3	Plant Held For Future Use	II (A)(1)(c)	-	13,571,504	Sheet 4, line 4	(1)
4	**Total Plant** (Line 1 + 2 + 3)		398,309,480	1,201,908,296		
5	Accumulated Depreciation	II (A)(1)(d)	(95,102,434)	(283,732,865)	Sheet 4, line 7	(1)
6	Accumulated Deferred Income Taxes	II (A)(1)(e)	(75,011,955)	(223,794,030)	Sheet 4, line 11	(1)
7	Loss On Reacquired Debt	II (A)(1)(f)	757,488	2,259,924	Sheet 4, line 12	(1)
8	Other Regulatory Assets	II (A)(1)(g)	4,930,985	14,711,323	Sheet 4, line 17	(2)
9	**Net Investment** (Line 4 + 5 + 6 + 7 + 8)		233,883,564	711,352,648		(2)
10	Prepayments	II (A)(1)(h)	2,283,784	6,813,544	Sheet 4, line 18	(1)
11	Materials & Supplies	II (A)(1)(II)	5,909,946	17,631,999	Sheet 4, line 19	(1)
12	Cash Working Capital	II (A)(1)(j)	1,117,679	3,269,052	Sheet 4, line 25	(2)
13	**Total Investment Base** (Line 9 + 10 + 11 + 12)		$ 243,194,973	$ 739,067,243		(2)
	Revenue Requirement					
14	Investment Return and Income Taxes	II (A)	$ 30,203,843	$ 93,265,654	Sheet 3a, Line 26	(2)
15	Depreciation Expense	II (B)	8,679,581	25,895,050	Sheet 5, Line 3	(1)
16	Amortization of Loss on Reacquired Debt	II (C)	58,839	175,544	Sheet 5, Line 4	(1)
17	Investment Tax Credit	II (D)	(77,133)	(230,121)	Sheet 5, Line 5	(1)
18	Property Taxes	II (E)	7,099,692	21,181,538	Sheet 5, Line 6	(1)
19	Payroll tax Expense	II (F)	269,960	805,411	Sheet 5, Line 24	(1)
20	Operation & Maintenance Expense	II (G)	4,580,096	13,664,461	Sheet 5, Line 11	(1)
21	Administrative & General Expense	II (H)	4,185,749	12,487,955	Sheet 5, Line 22	(2)
22	Transmission Related Integrated Facilities Charge	II (I)	-	-	N/A	(1)
23	Transmission Support Revenue	II (J)	(1,153,965)	-	Sheet 7, Line 9	(1)
24	Transmission Support Expense	II (K)	1,329,554	-	Sheet 7, Line 9	(1)
25	Transmission Related Expense from Generators	II (L)	-	-	N/A	(1)
26	Transmission Related Taxes and Fees Charge	II (M)	104,168	310,778	Sheet 5, Line 23	(1)
27	Revenue for ST Trans Service Under NEPOOL Tariff	II (N)	(35,083)	(104,467)	Attachment B, Lines 9 & 10	(1)
28	Transmission Rents Received for Electric Property	II (O)	(2,926,302)	-	Attachment C, Line 3	(1)
29	**Total Revenue Requirements** (Sum of Lines 14 through 28)		$ 52,318,999	$ 167,451,803		(2)
30	**Total Pre-1997 and Post 1996** (Line 29 [Pre-1997 + Post-1996])			$ 219,770,802		(2)

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.

(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements
Calculated under the Present Rates in Attachment F of the ISO-NE OATT
For Costs in 2014
Sheet 3a

Line	Description	Capitalization 12/31/14	Weighted Capitalization	Weighted Cost of Capital (a)	Weighted Cost of Capital	Equity Portion		Notes
	Col.A	Col.B	Col.C	Col.D	Col.E	Col.F		
1	Long-Term Debt	$ 1,792,712,148	41.74%	4.19%	1.75%		FF1 112.24(c)	(1)
2	Preferred Stock	43,000,000	1.00%	4.56%	0.05%	0.05%	FF1 112.3(c)	(1)
3	Common Equity	2,459,452,736	57.26%	11.07%	6.34%	6.34%	FF1 112.16(c) less Line 3(c)	(1)
4	Total Investment Return	$ 4,295,164,884	100.00%		8.14%	6.39%	Sum of Lines 1 to 3	(1)

ROE per ISO New England Inc. Transmission, Markets and Services Tariff, Section II Attachment F II.A.2.(iii), page 231 http://www.iso-ne.com/regulatory/tariff/sect_2/oatt/sect_ii.pdf

Line	Description	Pre-97	Post-96		Notes
5	**Federal Income Tax (FIT)**				
6	A= Preferred & Equity Return	6.39%	6.39%	Line 4, Col F	(1)
7	B= Transmission Related Amortization of ITC	$ (77,133)	$ (230,121)	Sheet 2a, Line 17	(1)
8	C= Equity AFUDC Component of Depreciation Expense	$ 18,983	$ 56,635	Sheet 10, Column (g)	(1)
9	D= Transmission Investment Base	$ 243,194,973	$ 739,067,243	Sheet 2a, Line 13	(2)
10	FT = Federal Income Tax Rate	35.00%	35.00%	Federal Income Tax Rate	(1)
11	FIT = (A+[C+B)/D])(FT)/(1-FT)	3.42790%	3.42810%	Federal Income Tax	(1)
12	ST = State Income Tax Rate	8.00%	8.00%	State Tax Rate	(1)
13	**State Income Tax (SIT)**				(1)
14	SIT = (A+[(C+B)/D]+Federal Income Tax)(ST)/(1-ST)	0.8517%	0.8517%	State Income Tax	(1)
15	Allowed Return	12.4196%	12.4198%	line 4, Col.E + Line 11 + Line 14	(1)
16	D= Transmission Investment Base	$ 243,194,973	$ 739,067,243	Sheet 2a, Line 13	(2)
17	**Return**	$ 30,203,843	$ 91,790,673	Line 15 * Line 16	(2)
18	Incremental return for Post 2003 PTF Investment				
19	A= Incremental Return		0.6700%	Per Opinion No. 489 and Opinion No. 531-B (b)	(1)
20	Effective Incremental (a')		0.3800%	line 19 * line 3, Col C	(1)
21	Additional FIT (a'/A')		0.2046%	Incremental FIT = (A' x FT)/(1-FT)	(1)
22	Additional SIT (a'/A')		0.0508%	Incremental SIT = (A' + FIT)(ST)/(1-ST)	(1)
23	Additional Return		0.6354%	Sum lines 20 thru 22	(1)
24	Post 2003 PTF net Investment		$ 232,134,198	Sheet 8, line 15	(1)
25	Additional 100 bp Return Post 2003 PTF Investment		$ 1,474,981	Line 23 * Line 24	(1)
26	Total Return	$ 30,203,843	$ 93,265,654	Line 17 + Line 25	(2)

Line	Description	Capitalization 12/31/14	Weighted Capitalization	Weighted Cost of Capital	Weighted Cost of Capital	Equity Portion	Notes
27	**Incremental return for PTF 50 Basis Point Adder**						
28	Long-Term Debt	$ 1,792,712,148	41.74%	4.19%	1.75%		(1)
29	Preferred Stock	43,000,000	1.00%	4.56%	0.05%		(1)
30	Common Equity	2,459,452,736	57.26%	0.50%	0.29%	0.29%	(1)
31	Total Investment Return	$ 4,295,164,884	100.00%		2.09%	0.29%	(1)

Line	Description	Pre-97	Post-96		Notes
32	**Federal Income Tax (FIT)**				
33	A= Incremental Return	0.29%	0.29%	Line 31, Col F	(1)
34	B= Transmission Related Amortization of ITC	$ -	$ -	N/A	(1)
35	C= Equity AFUDC Component of Depreciation Expense	$ -	$ -	N/A	(1)
36	D= Transmission Investment Base	$ 243,194,973	$ 739,067,243	Sheet 2a, Line 13	(2)
37	FT = Federal Income Tax Rate	35.00%	35.00%	Federal Income Tax Rate	(1)
38	FIT = (A+[C+B)/D])(FT)/(1-FT)	0.15620%	0.15620%	Federal Income Tax	(1)
39	ST = State Income Tax Rate	8.00%	8.00%	State Tax Rate	(1)
40	**State Income Tax (SIT)**				(1)
41	SIT = (A+[(C+B)/D]+Federal Income Tax)(ST)/(1-ST)	0.0388%	0.0388%	State Income Tax	(1)
					(1)
42	Allowed Return	0.4850%	0.4850%	line 33 + Line 38 + Line 41	(1)
43	D= Transmission Investment Base	$ 243,194,973	$ 739,067,243	Sheet 2a, Line 13	(2)
44	Return 50 bp Adder	$ 1,179,496	$ 3,584,476	Line 42 * Line 43	(2)
45	Total Return 50 bp Adder		$ 4,763,972	Line 44 Pre-97 + Line 44 Post 96	(2)
46	Total Incremental Return		$ 6,238,953	Line 25 + Line 45	(2)

(a) See Attachment F for weighted cost of debt and preferred stock support.
(b) As a result of Opinion No. 531-B, these projects receive an ROE incentive of 67 bp.

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements
Calculated under the Present Rates in Attachment F of the ISO-NE OATT
For Costs in 2014
Sheet 4

Line	Description	Total	Wage/Plant Allocation Factors		Transmission Allocated	Pre-97 PTF Allocation Factor (a)	Pre-97 PTF Allocated	Post-96 PTF Allocation Factor (a)	Post-96 PTF Allocated	Reference	Notes
	Col.A	Col.B	Col.C		Col.D (Col.B x Col.C)	Col.E	Col.F (Col.D x Col.E)	Col.G	Col.H (Col.D x Col.G)	Col.I	
	Transmission Plant										
1	Transmission Plant (exc SCADA)	$ 1,903,972,438			$ 1,903,972,438		$ 394,245,298		$ 1,176,211,529	Sheet 6, Line 1 (PTF) & Line 2 (Total)	(1)
2	General Plant	$ 186,941,660	10.4993%	(b)	$ 19,627,566	20.7065%	$ 4,064,182	61.7767%	$ 12,125,263	FF1 207.99(g)	(1)
3	Total Transmission Plant (line 1 + 2)				$ 1,923,600,004		$ 398,309,480		$ 1,188,336,792		(1)
4	Transmission Plant Held for Future Use	$ 13,571,504	100.0000%		$ 13,571,504	0.0000%	$ -	100.0000%	$ 13,571,504	FF1 214.14(d) to 18(d)	(1)
	Transmission Accumulated Depreciation										
5	Transmission Accum. Depreciation	$ (453,776,651)	100.0000%		$ (453,776,651)	20.7065%	$ (93,961,262)	61.7767%	$ (280,328,240)	FF1 219.25(b)	(1)
6	General Plant Accum.Depreciation	$ (52,490,917)	10.4993%	(b)	$ (5,511,179)	20.7065%	$ (1,141,172)	61.7767%	$ (3,404,625)	FF1 219.28(b)	(1)
7	Total Transmission Acc Dep (line 5 + 6)				$ (459,287,830)		$ (95,102,434)		$ (283,732,865)		(1)
	Transmission Accumulated Deferred Taxes										
8	Accumulated Deferred Taxes (282) (d)	$ (1,143,462,163)	28.4332%	(c)	$ (325,122,884)	20.7065%	$ (67,321,570)	61.7767%	$ (200,850,189)	FF1 275.9(k) - 275.4(k)	(1)
9	Accumulated Deferred Taxes (283)				$ (45,243,071)	20.7065%	$ (9,368,256)	61.7767%	$ (27,949,676)	Sheet 9, Line 25, Col D	(1)
10	Accumulated Deferred Taxes (190)				$ 8,103,112	20.7065%	$ 1,677,871	61.7767%	$ 5,005,835	Sheet 9, Line 10, Col D	(1)
11	Total ADIT (line 8 + 9 + 10)				$ (362,262,843)		$ (75,011,955)		$ (223,794,030)		(1)
12	Transmission loss on Reacquired Debt	$ 12,865,994	28.4332%	(c)	$ 3,658,214	20.7065%	$ 757,488	61.7767%	$ 2,259,924	FF1 111.81(c)	(1)
	Other Regulatory Assets										
13	Unamortized Balance of Transmission Merger-Related Costs	$ -	100.0000%		$ -					**Exhibit No. ES-220, Page 2 of 8, Line 3(D)**	(2)
14	FAS 106	$ -	10.4993%	(b)	$ -					FF1 232	(1)
15	ASC 740 Regulatory Asset (FAS 109)	$ 87,768,732	28.4332%	(c)	$ 24,955,459					FF1 232.29(f)	(1)
16	ASC 740 Regulatory Liability (FAS 109)	$ (4,015,556)	28.4332%	(c)	$ (1,141,751)					FF1 278.2(f)	(1)
17	Total (line 13 + 14 + 15)	$ 83,753,176			$ 23,813,708	20.7065%	$ 4,930,985	61.7767%	$ 14,711,323		(2)
18	Transmission Prepayments	$ 105,048,059	10.4993%	(b)	$ 11,029,311	20.7065%	$ 2,283,784	61.7767%	$ 6,813,544	FF1 111.57(c)	(1)
19	Transmission Materials and Supplies	$ 28,541,503	100.0000%		$ 28,541,503	20.7065%	$ 5,909,946	61.7767%	$ 17,631,999	FF1 227.8(c) + 227.5(c) Footnote	(1)
	Cash Working Capital										
20	Operation & Maintenance Expense						$ 4,580,096		$ 13,664,461	Sheet 5, line 11	
21	Administrative & General Expense						$ 4,185,749		$ 12,487,955	Sheet 5, line 22	(3)
22	Net Transmission Support Expense						$ 175,589		$ -	Sheet 7, line 9	(1)
23	Total (line 19 + 20 + 21)						$ 8,941,434		$ 26,152,416		(3)
24	45 day allowance per tariff						0.1250		0.1250	= 45 days / 360 days	(1)
25	Cash Working Capital (line 22 * 23)						$ 1,117,679		$ 3,269,052		(3)

(a) PTF Allocator (Sheet 6, Line 3)
(b) Wages & Salaries Allocator (Sheet 6, Line 13)
(c) Plant Allocator (Sheet 6, Line 18)
(d) ADIT in FERC Account 282 excludes ADIT associated with transition property from FF1 275.4(k)

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Proposed revisions reflect the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset
(3) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated PTF Revenue Requirements
Calculated under the Present Rates in Attachment F of the ISO-NE OATT
For Costs in 2014
Sheet 5

						Pre-97 PTF		Post-96 PTF			
Line	Description	Total	Wage/Plant Allocation Factors		Transmission Allocated	Allocation Factor (a)	Pre-97 PTF Allocated	Allocation Factor (a)	Post-96 PTF Allocated	Reference	Notes
	Col.A	Col.B	Col.C		Col.D (Col.B x Col.C)	Col.E	Col.F (Col.D x Col.E)	Col.G	Col.H (Col.D x Col.G)	Col.I	
	Depreciation Expense										
1	Transmission Depreciation	$ 41,001,613			$ 41,001,613	20.7065%	$ 8,489,999	61.7767%	$ 25,329,443	FF1 336.7(b)	(1)
2	General Depreciation	$ 8,720,270	10.4993%	(b)	$ 915,567	20.7065%	$ 189,582	61.7767%	$ 565,607	FF1 336.10(b)	(1)
3	Total (line 1 + 2)	$ 49,721,883			$ 41,917,180		$ 8,679,581		$ 25,895,050		(1)
4	Amortization of Loss on Reacquired Debt	$ 999,391	28.4332%	(c)	$ 284,159	20.7065%	$ 58,839	61.7767%	$ 175,544	FF1 117.64(c)	(1)
5	Amortization of Investment Tax Credits	$ 1,310,106	28.4332%	(c)	$ 372,505	20.7065%	$ 77,133	61.7767%	$ 230,121	FF1 114.19(c)	(1)
	Property Taxes										
6	Transmission Property Taxes	$ 120,588,821	28.4332%	(c)	$ 34,287,261	20.7065%	$ 7,099,692	61.7767%	$ 21,181,538	FF1 263.5(i)	(1)
	Transmission Operation and Maintenance										
7	Operation and Maintenance	$ 362,540,896			$ 362,540,896	20.7065%	$ 75,069,531	61.7767%	$ 223,965,802	FF1 321.112(b)	(1)
8	less: Transmission of Electricity by Others (565)	$ 324,980,606			$ 324,980,606	20.7065%	$ 67,292,109	61.7767%	$ 200,762,294	FF1 321.96(b)	(1)
9	less: Load Dispatching (561 to 561.4)	$ 15,426,418			$ 15,426,418	20.7065%	$ 3,194,271	61.7767%	$ 9,529,932	FF1 321.85(b) through 321.88(b)	(1)
10	less: Rents (567)	$ 14,755			$ 14,755	20.7065%	$ 3,055	61.7767%	$ 9,115	FF1 321.98(b)	(1)
11	O&M for RNS Tariff (line 7 - 8 - 9 - 10)	$ 22,119,117			$ 22,119,117		$ 4,580,096		$ 13,664,461		(1)
	Transmission Administrative and General										
12	Administrative and General	$ 145,329,829								FF1 323.197(b)	(1)
13	less: Property Insurance (924)	$ 926,016								FF1 323.185(b)	(1)
14	less: Regulatory Commission Expenses (928)	$ 9,560,209								FF1 323.189(b)	(1)
15	less: Miscellaneous General Expenses (930.2) (d)	$ 52,118								FF1 232.2.14(e)	(1)
16	less: General Advertising Expense (930.1)	$ 32,018								FF1 323.191(b)	(1)
17	less: Merger-Related Costs	$ -									(2)
18	Subtotal (line 12 - sum of lines 13 through 16)	$ 134,759,468	10.4993%	(b)	$ 14,148,801	20.7065%	$ 2,929,721	61.7767%	$ 8,740,662		(1)
19	plus: Property Insurance (line 13)	$ 926,016	28.4332%	(c)	$ 263,296	20.7065%	$ 54,519	61.7767%	$ 162,656	FF1 323.185(b)	(1)
20	plus: Regulatory Comm. Exp (T FERC Assessments)	$ 1,992,376	100.0000%		$ 1,992,376	20.7065%	$ 412,551	61.7767%	$ 1,230,824	FF1 350.6(d)	(1)
21	plus: Transmission Merger-Related Costs	$ 3,810,195	100.0000%		$ 3,810,195	20.7065%	$ 788,958	61.7767%	$ 2,353,813	**Exhibit No. ES-220, Page 2 of 8, Line 2(D)**	(2)
22	Total A&G for RNS Tariff (Line 17 + 18 + 19)	$ 141,488,055			$ 20,214,668		$ 4,185,749		$ 12,487,955		(2)
23	Transmission Related Taxes and Fees	$ 1,769,295	28.4332%	(c)	$ 503,067	20.7065%	$ 104,168	61.7767%	$ 310,778	FF1 263.8(i)+14(i)+19(i)	(1)
24	Payroll Tax Expense	$ 12,417,455	10.4993%	(b)	$ 1,303,746	20.7065%	$ 269,960	61.7767%	$ 805,411	FF1 263.10(i)+15(i)+18(i)	(1)

(a) PTF Allocator (Sheet 6, Line 3)
(b) Wages & Salaries Allocator (Sheet 6, Line 13)
(c) Plant Allocator (Sheet 6, Line 18)
(d) NSTAR Green Program costs are excludable for Transmission billing purposes.

Notes:
(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Exhibit No. ES-223
Schedule 1

Summary of Impact on NSTAR Electric SCADA Revenue Requirements under Schedule 1, Appendix A of the ISO-NE OATT (3-year amortization)

Eversource Energy Service Company

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Summary of Impact on SCADA Revenue Requirements
Under Schedule 1, Appendix A
For the Calendar years 2016 - 2018

Line	(A) Description	(B) Total Schedule 1 Revenue Requirements under present rates in Appendix A		(C) Total Schedule 1 Revenue Requirements under changed rates in Appendix A		(D) = (C) - (B) Difference (5) (Rounded to '000s)	(E) = (D)/(B) % Difference
1	2016 Estimated Schedule 1 Revenue Requirements	$ 6,785,703	(1)	$ 6,818,448	(2)	$ 33,000	0.5%
2	2017 Estimated Schedule 1 Revenue Requirements	$ 6,785,703	(1)	$ 6,815,229	(3)	$ 30,000	0.4%
3	2018 Estimated Schedule 1 Revenue Requirements	$ 6,785,703	(1)	$ 6,812,004	(4)	$ 26,000	0.4%

Notes

(1) Exhibit No. ES-223, Schedule 2, Page 1 of 6, Line 9(C)
(2) Exhibit No. ES-223, Schedule 3, Page 1 of 6, Line 9(C)
(3) Exhibit No. ES-223, Schedule 4, Page 1 of 6, Line 9(C)
(4) Exhibit No. ES-223, Schedule 5, Page 1 of 6, Line 9(C)
(5) In connection with the three-year amortization alternative (with the proposed effective date of June 1, 2016), Eversource is showing the revenue impact for the thirty-six month period June 1, 2016 through May 31, 2019. Eversource is using calendar year revenue requirement calculations as estimates for the thirty-six month period beginning June 1, 2016. See Cooper Testimony Exhibit No. ES-200.

	2016	2017	2018	2019	Total
The amounts for each year are as follows:	$ 19,000	$ 31,000	$ 28,000	$ 11,000	$ 89,000

Exhibit No. ES-223
Schedule 2

SCADA Revenue Requirements under Present Rates for the Calendar Years 2016 - 2018

Eversource Energy Service Company

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated SCADA Revenue Requirements Under Present Rates
Under Schedule 1, Appendix A
For the Calendar Years 2016 - 2018

	(A)	(B)	(C)
Line	**Description**	**Reference**	**Total NSTAR Electric**
1	2014 Actual SCADA Revenue Requirement	Exhibit No. ES-223, Schedule 2, Page 2 of 6, Line 26(c)	$ 6,785,703
2	Estimated 2015 SCADA Plant Additions	(1)	$ -
3	Carrying Charge Factor (CCF)	(1)	0.00%
4	2015 Incremental Estimated SCADA Revenue Requirement	Line 2 x 3	-
5	Total Estimated SCADA Revenue Requirement for 2015	Line 1 + 4	$ 6,785,703
6	Estimated 2016 SCADA Plant Additions	(1)	$ -
7	Carrying Charge Factor (CCF)	(1)	0.00%
8	2016 Incremental Estimated SCADA Revenue Requirement	Line 6 x 7	-
9	Total Estimated SCADA Revenue Requirement for 2016	Line 5 + 8	$ 6,785,703

Notes:
(1) There is no forecasted SCADA plant.
(2) The revenue requirements calculations for the calendar year 2016 (including any forecast for 2016) are used as an estimate for the revenue requirements for 2017 and 2018, which are used to calculate the revenue impact of the proposed cost recovery.

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated SCADA Revenue Requirements Under Present Rates
Under Schedule 1, Appendix A
Total Revenue Requirements For the Calendar year 2014
Sheet 1

Line	(a) Description	(b) Tariff Section	(c) Amount	(d) Reference	(e) Notes
1	Dispatch Center Investment Base	A.1			
2	Dispatch Center Plant	A.1.a	$ 11,320,255	Sheet 3, Line 1(f)	(1)
3	Dispatch Center Related General Plant	A.1.b	$ 4,463,606	Sheet 3, Line 2(f)	(1)
4	Dispatch Center Plant Held for Future Use	A.1.c	$ -	Sheet 3, Line 3(f)	(1)
5	Total Plant (line 2 + 3 + 4)		$ 15,783,861		
6	Dispatch Center Related Depreciation Reserve	A.1.d	$ 6,017,455	Sheet 3, Line 7(f)	(1)
7	Dispatch Center Related Accumulated Deferred Taxes	A.1.e	$ 4,962,888	Sheet 3, Line 13(f)	(1)
8	Total Net Plant (line 5 - 6 - 7)		$ 4,803,518		
9	Other Regulatory Assets	A.1.f	$ 195,396	Sheet 3, Line 18(f)	(2)
10	Dispatch Center Prepayments	A.1.g	$ 2,508,233	Sheet 3, Line 19(f)	(1)
11	Disptach Center Materials & Supplies	A.1.h	$ 66,587	Sheet 3, Line 20(f)	(1)
12	Dispatch Center Related Cash Working Capital	A.1.i	$ 811,948	Sheet 3, Line 24(f)	(2)
13	Total Dispatch Center Investment Base (sum of lines [8-12])		$ 8,385,682		
14	Revenue Requirements				
15	Investment Return and Income Taxes	A.2	$ 1,042,064	Sheet 2, Line 38(c)	(2)
16	Disptach Center Depreciation Expense	B	$ 484,934	Sheet 4, Line 4(f)	(1)
17	Dispatch Center Related Amortization of Investment Tax Credits	C	$ (3,056)	Sheet 4, Line 5(f)	(1)
18	Dispatch Center Related Municipal Tax Expense	D	$ 281,334	Sheet 4, Line 6(f)	(1)
19	Dispatch Center Related Payroll Tax Expense	E	$ 296,376	Sheet 4, Line 7(f)	(1)
20	Dispatch Center Operation & Maintenance Expense	F	$ 3,271,123	Sheet 4, Line 14(f)	(1)
21	Dispatch Center Related Administrative and General Expenses	G	$ 3,224,460	Sheet 4, Line 24(f)	(2)
22	Total Revenue Requirements (sum of lines [15-21])		$ 8,597,235		
23	PTF Transmission Plant Allocator		82.4832%	NSTAR PTF Sheet 6, Line 4	(1)
24	PTF Revenue Requirement for SCADA (line 22 * 24)		$ 7,091,275		
25	PTF Transmission Plant Allocator		(305,572)	Exhibit 1	(1)
26	PTF Revenue Requirement for SCADA (line 22 * 24)		$ 6,785,703		

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.

(2) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000. Provided this support because these balances will be revised under the changed rates.

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated SCADA Revenue Requirements Under Present Rates
Under Schedule 1, Appendix A
Investment Return and Income Tax Calculation For the Calendar year 2014
Sheet 2

Line	(a) Description	(b) Tariff Section	(c) Balance	(d) Capitalization Ratio	(e) Cost	(f) Weighted Cost	(g) Equity Cost	(h) Reference	(I) Notes
1	Weighted Cost of Capital	A.2.a							
2	Long Term Debt	A.2 a.i	$ 1,792,712,148	41.74%	4.22%	1.76%		Page 112.24(c)	(1)
3	Preferred Stock	A.2.a.ii	$ 43,000,000	1.00%	4.56%	0.05%	0.05%	Page 112.3(c)	(1)
4	Common Equity	A.2.a.iii	$ 2,459,452,736	57.26%	11.07%	6.34%	6.34%	Page 112.16(c) (less Line 3)	(1)
5	Total (line 2 + 3 + 4)		$ 4,295,164,884	100 00%		8.15%	6.39%		
6	Total Investment Base		$ 8,385,682					Sheet 1, Line 13(c)	(2)
7	Weighted Cost of Capital		8.15%					Line 5(f)	
8	Total Return on Investment		$ 683,433					Line 6 * Line 7	
9	Federal Income Tax	A 2.b							
10	A = Equity Cost		6.39%					Line 5(g)	
11	B = Transmission Amortization of ITC		$ (3,056)					Sheet 4, Line 5(f)	(1)
12	C = Equity AFUDC		$ 700						
13	Total B + C		$ (2,356)					Line 11 + Line 12	
14	D = Investment Base		$ 8,385,682					Line 6	(2)
15	(B + C) / D		-0.0281%					Line 13 / Line 14	
16	(A + [(C + B) / D])		6.3619%					Line 10 + Line 15	
17	FT = Federal Income Tax Rate		35.00%						
18	1 - FT		65.00%					1 - Line 17	
19	Federal Tax Factor		3.4256%					Line 16 * Line 17 / Line 18	
20	Total Federal Income Taxes		$ 287,260					Line 14 * Line 19	
21	State Income Tax	A.2.c							
22	A = Equity Cost		6.39%					Line 5(g)	
23	B = Transmission Amortization of ITC		$ (3,056)					Sheet 4, Line 5(f)	(1)
24	C = Equity AFUDC		$ 700.00						
25	Total B + C		$ (2,356)					Line 23 + Line 24	
26	D = Investment Base		$ 8,385,682					Line 6	(2)
27	(B + C) / D		-0.0281%					Line 25 / Line 26	
28	(A + [(C + B) / D])		6.3619%					Line 22 + Line 27	
29	ST = State Income Tax Rate		8.00%						
30	1 - ST		92.00%					1 - Line 29	
31	Federal Tax Factor		3.4256%					Line 19	
32	State Tax Factor		0.8511%					(Line 28 + Line 31) * Line 29 / Line 30	
33	Total State Income Taxes		$ 71,371					Line 26 * Line 32	
34	Investment Return and Income Taxes	A.2							
35	Return on Investment		$ 683,433					Line 8	
36	Federal Income Taxes		$ 287,260					Line 20	
37	State Income Taxes		$ 71,371					Line 33	
38	Total Investment Return and Income Taxes		$ 1,042,064					Sum Lines 35 thru 37	
39	Value of 50BP ROE Adder								
40	ROE Adder		0.50%					Per Tariff	
41	Equity Ratio		57.26%					Line 4(d)	
42	Effective Adder		0.29%					Line 40 * Line 41	
43	Tax Gross-up		0.1949%					Line 42 * .6722408	
44	Adder plus Gross-up		0.4849%					Line 42 + Line 43	
45	Rate Base		$ 8,385,682					Line 6	
46	Earned Adder		$ 40,662					Line 44 * Line 45	
47	PTF Ratio		82.4832%					RNS Sheet 6	(1)
48	PTF Related Adder		$ 33,539					Line 46 * Line 47	

Notes

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NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated SCADA Revenue Requirements Under Present Rates
Under Schedule 1, Appendix A
Rate Base Items For the Calendar year 2014
Sheet 3

Line	(a) Description	(b) Tariff Section	(c) Total	(d) Allocator	(e) Allocation Factor	(f) Dispatch Center Allocated	(g) Reference	(h) Notes
1	Dispatch Center Plant	A.1.a				$ 11,320,255	Sheet 6, Line 12(c)	(1)
2	Dispatch Center Related General Plant	A.1.b	$ 186,941,660	W&S	2.3877%	$ 4,463,606	FF1 207.99(g)	(1)
3	Dispatch Center Plant Held for Future Use	A.1.c				$ -	FF1 214	(1)
4	Dispatch Center Related Depreciation Reserve	A.1.d						
5	Dispatch Center Depreciation Reserve					$ 4,764,129	FF1 219.25(b) (part)	(1)
6	Transmission Related General Depreciation Reserve		$ 52,490,917	W&S	2.3877%	$ 1,253,326	FF1 219.28(b)	(1)
7	Total Dispatch Center Related Depreciation Reserve (line 5 6)					$ 6,017,455		
8	Dispatch Center Related Accumulated Deferred Taxes	A.1.e						
9	ADIT - Accelerated Amortization Property (Acct #281)		$ -	Plant	0.2333%	$ -	FF1 273.17(k)	(1)
10	ADIT - Other Property (Acct #282)		$ 1,143,462,163	Plant	0.2333%	$ 2,667,697	Line 27	(1)
11	ADIT - Other (Acct #283)					$ 2,876,873	Sheet 7, Line 30(d)	(1)
12	Less ADIT (Acct #190)					$ 581,682	Sheet 7, Line 12(d)	(1)
13	Total Dispatch Center Related ADIT (ine 9 10 11 - 12)					$ 4,962,888		
14	Other Regulatory Assets	A.1.f						
15	FAS 106		$ -	W&S	2.3877%	$ -	FF1 232.1	(1)
16	ASC 740 Regulatory Asset (FAS 109)		$ 87,768,732	Plant	0.2333%	$ 204,764	FF1 232.29(f)	(1)
17	Less ASC 740 Regulatory Liability (FAS 109)		$ 4,015,556	Plant	0.2333%	$ 9,368	FF1 278.1(f)	(1)
18	Total Other Regulatory Assets (line 15 16 - 17)		$ 83,753,176			$ 195,396		(2)
19	Dispatch Center Prepayments	A.1.g	$ 105,048,059	W&S	2.3877%	$ 2,508,233	FF1 111.57(c)	(1)
20	Dispatch Center Materials and Supplies	A.1.h	$ 28,541,503	Plant	0.2333%	$ 66,587	FF1 227.8(c) + 5(c) fn	(1)
21	Dispatch Center Related Cash Working Capital	A.1.i						
22	Dispatch Center Operation and Maintenance Expense		$ 3,271,123	WC	12.50%	$ 408,890	Sheet 4, Line 14(f)	(1)
23	Dispatch Center Related Administrative and General Expense		$ 3,224,460	WC	12.50%	$ 403,058	Sheet 4, Line 24(f)	(2)
24	Total Dispatch Center Related Cash Working Capital (line 22 23)		$ 6,495,583			$ 811,948		(2)
25	Account 282		$ 1,143,462,163	FF1 275.9(k)				
26	less amounts related to divestiture		$ -	FF1 275.4(k)				
27	Total Account 282 (line 25 26)		$ 1,143,462,163					

Notes:

Line	Description	Allocation Factor	Reference	Notes
28	Wages & Salary Allocation (W&S)	2.3877%	Sheet 6, Line 6(c)	(1)
29	Plant Allocation Allocation (Plant)	0.2333%	Sheet 6, Line 16(c)	(1)
30	Cash Working Capital (WC)	12.50%	OATT - Schedule 1, A.1.i	(1)

Notes:

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NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated SCADA Revenue Requirements Under Present Rates
Under Schedule 1, Appendix A
Expense Items For the Calendar year 2014
Sheet 4

Line	(a) Description	(b) Tariff Section	(c) Total	(d) Allocator	(e) Allocation Factor	(f) = (c) * (e) Dispatch Center Allocated	(g) Reference	(h) Notes
1	Dispatch Center Depreciation Expense	B						
2	Dispatch Center Plant Depreciation Expense					$ 276,720	See Line 31(d)	(1)
3	General Plant Depreciation Expense		$ 8,720,270	W&S	2.3877%	$ 208,214	FF1 336.10(b)	(1)
4	Total Dispatch Center Depreciation Expense (ine 2 3)					$ 484,934		
5	Dispatch Center Related Amortization of Investment Tax Credits	C	$ (1,310,106)	Plant	0.2333%	$ (3,056)	FF1 266.8(f) & 11(f)	(1)
6	Dispatch Center Related Municipal Tax Expense	D	$ 120,588,821	Plant	0.2333%	$ 281,334	FF1 263.5(i)	(1)
7	Dispatch Center Related Payroll Tax Expense	E	$ 12,412,619	W&S	2.3877%	$ 296,376	FF1 263.10(i)	(1)
8	Dispatch Center Operations & Maintenance Expense	F						
9	Load dispatching #561		$ -	Direct	100.0000%	$ -	FF1 321.84(b)	(1)
10	Load dispatching - Reliability #561.1		$ 1,389,220	Direct	100.0000%	$ 1,389,220	FF1 321.85(b)	(1)
11	Load dispatching - Mon & Oper Trans System 561.2		$ 1,311,222	Direct	100.0000%	$ 1,311,222	FF1 321.86(b)	(1)
12	Load dispatching - Trans Service & Scheduling #561.3		$ 570,681	Direct	100.0000%	$ 570,681	FF1 321.87(b)	(1)
13	Scheduling, System Control and Dispatch Services #561.4		$ 12,155,295		0%	$ -	FF1 321.88(b)	(1)
14	Total Dispatch Center O&M Expense (sum of lines [9-13])		$ 15,426,418			$ 3,271,123		
15	Dispatch Center Related Administrative & General Expenses	G						
16	Administrative and General Expenses		$ 145,329,829				FF1 323.197(b)	(2)
17	less: Property Insurance (Acct #924)		$ 926,016				FF1 323.185(b)	(1)
18	less: Regulatory Commission Expenses (Acct #928)		$ 9,560,209				FF1 323.189(b)	(1)
19	less: General Advertising Expenses (Acct #930.1)		$ 32,018				FF1 323.191(b)	(1)
20	less: Miscellaneous General Expenses (Acct #930.2) '(1)		$ 52,118				FF1 323.192(b) fn	(1)
21	Subtotal (line 16 - sum of lines[17-20])		$ 134,759,468	W&S	2.3877%	$ 3,217,652		
22	Property Insurance		$ 926,016	Plant	0.2333%	$ 2,160	FF1 323.185(b)	(1)
23	FERC Assessments in Regulatory Commission Expenses (Acct #928)		$ 1,992,376	Plant	0.2333%	$ 4,648	FF1 350.7(d)	(1)
24	Total Dispatch Center Related A&G Expenses (sum of lines [21-23])		$ 137,677,860			$ 3,224,460		(2)

NOTES:

Line	Description	Allocation Factor	Reference	Notes
25	Direct Allocation (Direct)	100.0000%		(1)
26	Wages & Salaries Allocation (W&S)	2.3877%	Sheet 6, Line 6(c)	(1)
27	Plant Allocation (Plant)	0.2333%	Sheet 6, Line 16(c)	(1)

Line	Description	Total Investment	Life Depr. Rate	Depreciation Expense	Reference	Notes
28	Mass. Ave. Service Center - 431 (Trans. Station Equipment)	$ 7,966,151	2.53%	$ 201,464	Sheet 6, Line 9(c)	(1)
29	SCADA Mass. Ave. - 421 (Trans. & Conversion Station Structures)	$ 2,816,142	2.19%	$ 61,646	Sheet 6, Line 10(c)	(1)
30	SCADA Mass. Ave. - 431 (Trans. Station Equipment)	$ 537,962	2.53%	$ 13,610	Sheet 6, Line 11(c)	(1)
31	Total	$ 11,320,255		$ 276,720	Sum Lines 28 thru 30	

(1) NSTAR Green Program costs are excludable for Transmission billing purposes. Reflects actual information per Eversource's accounting records.

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.

(2) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000. Provided this support because these balances will be revised under the changed rates.

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated SCADA Revenue Requirements Under Present Rates
Under Schedule 1, Appendix A
Allocation Calculations For the Calendar year 2014
Sheet 6

Line	(a) Description	(b) Tariff Section		(c) Amount	(d) Reference	(e) Notes
1	Dispatch Center Wages & Salaries Allocation Factor	Definitions				
2	Direct Dispatch Center Wages & Salaries		$	2,858,118	Note (a)	(1)
3	NSTAR Electric Direct Wages & Salaries		$	152,023,518	FF1 354.28(b)	(1)
4	Less: Administrative & General Wages & Salaries		$	32,322,705	FF1 354.27(b)	(1)
5	Net NSTAR Electric Wages & Salaries (line 3 - 4)		$	119,700,813		
6	Wages & Salaries Allocation Factor (line 2 / 5)			2.3877%		
7	Dispatch Center Plant Allocation Factor	Definitions				
8	Investment In Dispatch Center Plant					
9	Mass. Ave. Service Center - 431 (Trans. Station Equipment)		$	7,966,151	Note (a)	(1)
10	SCADA Mass. Ave. - 421 (Trans. & Conversion Station Structures)		$	2,816,142	↓	(1)
11	SCADA Mass. Ave. - 431 (Trans. Station Equipment)		$	537,962		(1)
12	Total Investment in Dispatch Center Plant (line 9 + 10 + 11)		$	11,320,255		
13	Dispatch Center Related General Plant		$	4,463,606	Sheet 3, Line 2(f)	(1)
14	Total Dispatch Center Plant Investment (line 12 + 13)		$	15,783,861		
15	Total Plant in Service		$	6,765,341,609	FF1 207.104(g)	(1)
16	Plant Allocation Factor (line 14 / 15)			0.2333%		

Note (a): Reflects actual information per Eversource's accounting records.

Notes

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.

(2) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000. Provided this support because a new allocation factor is calculated under changed rates

Exhibit No. ES-223
Schedule 3

SCADA Revenue Requirements under Changed Rates for the Calendar Year 2016

Eversource Energy Service Company

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated SCADA Revenue Requirement Under Changed Rates
Under Schedule 1, Appendix A
For the Calendar year 2016

	(A)	(B)	(C)
Line	**Description**	**Reference**	**Total NSTAR Electric**
1	2014 Actual SCADA Revenue Requirement	Exh bit No. ES-223, Schedule 3, Page 2 of 6, Line 26(c)	$ 6,818,448
2	Estimated 2015 SCADA Plant Additions	(1)	$ -
3	Carrying Charge Factor (CCF)	(1)	0.00%
4	2015 Incremental Estimated SCADA Revenue Requirement	Line 2 x 3	-
5	Total Estimated SCADA Revenue Requirement for 2015	Line 1 + 4	$ 6,818,448
6	Estimated 2016 SCADA Plant Additions	(1)	$ -
7	Carrying Charge Factor (CCF)	(1)	0.00%
8	2016 Incremental Estimated SCADA Revenue Requirement	Line 6 x 7	-
9	Total Estimated SCADA Revenue Requirement for 2016	Line 5 + 8	$ 6,818,448

Notes:
(1) There is no forecasted SCADA plant.

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated SCADA Revenue Requirement Under Changed Rates
Under Schedule 1, Appendix A
Total Revenue Requirements For the Calendar year 2014
Sheet 1

Line	(a) Description	(b) Tariff Section	(c) Amount	(d) Reference	(e) Notes
1	Dispatch Center Investment Base	A.1			
2	Dispatch Center Plant	A.1.a	$ 11,320,255	Sheet 3, Line 1(f)	(1)
3	Dispatch Center Related General Plant	A.1.b	$ 4,463,606	Sheet 3, Line 2(f)	(1)
4	Dispatch Center Plant Held for Future Use	A.1.c	$ -	Sheet 3, Line 3(f)	(1)
5	Total Plant (line 2 + 3 + 4)		$ 15,783,861		
6	Dispatch Center Related Depreciation Reserve	A.1.d	$ 6,017,455	Sheet 3, Line 7(f)	(1)
7	Dispatch Center Related Accumulated Deferred Taxes	A.1.e	$ 4,962,888	Sheet 3, Line 13(f)	(1)
8	Total Net Plant (line 5 - 6 - 7)		$ 4,803,518		
9	Other Regulatory Assets	A.1.f	$ 258,196	Sheet 3, Line 19(f)	(2)
10	Dispatch Center Prepayments	A.1.g	$ 2,508,233	Sheet 3, Line 20(f)	(1)
11	Disptach Center Materials & Supplies	A.1.h	$ 66,587	Sheet 3, Line 21(f)	(1)
12	Dispatch Center Related Cash Working Capital	A.1.i	$ 815,873	Sheet 3, Line 25(f)	(2)
13	Total Dispatch Center Investment Base (sum of lines [8-12])		$ 8,452,407		
14	Revenue Requirements				
15	Investment Return and Income Taxes	A.2	$ 1,050,363	Sheet 2, Line 38(c)	(2)
16	Disptach Center Depreciation Expense	B	$ 484,934	Sheet 4, Line 4(f)	(1)
17	Dispatch Center Related Amortization of Investment Tax Credits	C	$ (3,056)	Sheet 4, Line 5(f)	(1)
18	Dispatch Center Related Municipal Tax Expense	D	$ 281,334	Sheet 4, Line 6(f)	(1)
19	Dispatch Center Related Payroll Tax Expense	E	$ 296,376	Sheet 4, Line 7(f)	(1)
20	Dispatch Center Operation & Maintenance Expense	F	$ 3,271,123	Sheet 4, Line 14(f)	(1)
21	Dispatch Center Related Administrative and General Expenses	G	$ 3,255,860	Sheet 4, Line 26(f)	(2)
22	Total Revenue Requirements (sum of lines [15-21])		$ 8,636,934		
23	PTF Transmission Plant Allocator		82.4832%		(1)
24	PTF Revenue Requirement for SCADA (line 22 * 24)		$ 7,124,020		
25	PTF Transmission Plant Allocator		(305,572)	Exhibit 1	(1)
26	PTF Revenue Requirement for SCADA (line 22 * 24)		$ 6,818,448		

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.

(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated SCADA Revenue Requirement Under Changed Rates
Under Schedule 1, Appendix A
Investment Return and Income Tax Calculation For the Calendar year 2014
Sheet 2

Line	(a) Description	(b) Tariff Section	(c) Balance	(d) Capitalization Ratio	(e) Cost	(f) Weighted Cost	(g) Equity Cost	(h) Reference	(I) Notes
1	Weighted Cost of Capital	A.2.a							
2	Long Term Debt	A.2 a.i	$ 1,792,712,148	41.74%	4.22%	1.76%		Page 112.24(c)	(1)
3	Preferred Stock	A.2.a.ii	$ 43,000,000	1.00%	4.56%	0.05%	0.05%	Page 112.3(c)	(1)
4	Common Equity	A.2.a.iii	$ 2,459,452,736	57.26%	11.07%	6.34%	6.34%	Page 112.16(c) (less Line 3)	(1)
5	Total (line 2 + 3 + 4)		$ 4,295,164,884	100 00%		8.15%	6.39%		
6	Total Investment Base		$ 8,452,407					Sheet 1, Line 13(c)	(2)
7	Weighted Cost of Capital		8.15%					Line 5(f)	
8	Total Return on Investment		$ 688,871					Line 6 * Line 7	
9	Federal Income Tax	A 2.b							
10	A = Equity Cost		6.39%					Line 5(g)	
11	B = Transmission Amortization of ITC		$ (3,056)					Sheet 4, Line 5(f)	(1)
12	C = Equity AFUDC		$ 700						
13	Total B + C		$ (2,356)					Line 11 + Line 12	
14	D = Investment Base		$ 8,452,407					Line 6	
15	(B + C) / D		-0.0279%					Line 13 / Line 14	
16	(A + [(C + B) / D])		6.3621%					Line 10 + Line 15	
17	FT = Federal Income Tax Rate		35.00%						
18	1 - FT		65.00%					1 - Line 17	
19	Federal Tax Factor		3.4257%					Line 16 * Line 17 / Line 18	
20	Total Federal Income Taxes		$ 289,554					Line 14 * Line 19	
21	State Income Tax	A.2.c							
22	A = Equity Cost		6.39%					Line 5(g)	
23	B = Transmission Amortization of ITC		$ (3,056)					Sheet 4, Line 5(f)	(1)
24	C = Equity AFUDC		$ 700.00						
25	Total B + C		$ (2,356)					Line 23 + Line 24	
26	D = Investment Base		$ 8,452,407					Line 6	
27	(B + C) / D		-0.0279%					Line 25 / Line 26	
28	(A + [(C + B) / D])		6.3621%					Line 22 + Line 27	
29	ST = State Income Tax Rate		8.00%						
30	1 - ST		92.00%					1 - Line 29	
31	Federal Tax Factor		3.4257%					Line 19	
32	State Tax Factor		0.8511%					(Line 28 + Line 31) * Line 29 / Line 30	
33	Total State Income Taxes		$ 71,938					Line 26 * Line 32	
34	Investment Return and Income Taxes	A.2							
35	Return on Investment		$ 688,871					Line 8	
36	Federal Income Taxes		$ 289,554					Line 20	
37	State Income Taxes		$ 71,938					Line 33	
38	Total Investment Return and Income Taxes		$ 1,050,363					Sum Lines 35 thru 37	
39	Value of 50BP ROE Adder								
40	ROE Adder		0.50%					Per Tariff	
41	Equity Ratio		57.26%					Line 4(d)	
42	Effective Adder		0.29%					Line 40 * Line 41	
43	Tax Gross-up		0.1949%					Line 42 * .6722408	
44	Adder plus Gross-up		0.4849%					Line 42 + Line 43	
45	Rate Base		$ 8,452,407					Line 6	
46	Earned Adder		$ 40,986					Line 44 * Line 45	
47	PTF Ratio		82.4832%					RNS Sheet 6	(1)
48	PTF Related Adder		$ 33,807					Line 46 * Line 47	

Notes

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.

(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated SCADA Revenue Requirement Under Changed Rates
Under Schedule 1, Appendix A
Rate Base Items For the Calendar year 2014
Sheet 3

Line	(a) Description	(b) Tariff Section	(c) Total	(d) Allocator	(e) Allocation Factor	(f) Dispatch Center Allocated	(g) Reference	(h) Notes
1	Dispatch Center Plant	A.1.a				$ 11,320,255	Sheet 6, Line 12(c)	(1)
2	Dispatch Center Related General Plant	A.1.b	$ 186,941,660	W&S	2.3877%	$ 4,463,606	FF1 207.99(g)	(1)
3	Dispatch Center Plant Held for Future Use	A.1.c				$ -	FF1 214	(1)
4	Dispatch Center Related Depreciation Reserve	A.1.d						
5	Dispatch Center Depreciation Reserve					$ 4,764,129	FF1 219.25(b) (part)	(1)
6	Transmission Related General Depreciation Reserve		$ 52,490,917	W&S	2.3877%	$ 1,253,326	FF1 219.28(b)	(1)
7	Total Dispatch Center Related Depreciation Reserve (line 5 6)					$ 6,017,455		
8	Dispatch Center Related Accumulated Deferred Taxes	A.1.e						
9	ADIT - Accelerated Amortization Property (Acct #281)		$ -	Plant	0.2333%	$ -	FF1 273.17(k)	(1)
10	ADIT - Other Property (Acct #282)		$ 1,143,462,163	Plant	0.2333%	$ 2,667,697	Line 27	(1)
11	ADIT - Other (Acct #283)					$ 2,876,873	Sheet 7, Line 30(d)	(1)
12	Less ADIT (Acct #190)					$ 581,682	Sheet 7, Line 12(d)	(1)
13	Total Dispatch Center Related ADIT (ine 9 10 11 - 12)					$ 4,962,888		
14	Other Regulatory Assets	A.1.f						
15	Unamortized balance of merger-related transmission costs		$ 7,620,390	Direct	0.8241%	$ 62,800	Exhibit No. ES-220, Page 2 of 8, Line 3(B)	(2)
16	FAS 106		$ -	W&S	2.3877%	$ -	FF1 232.1	(1)
17	ASC 740 Regulatory Asset (FAS 109)		$ 87,768,732	Plant	0.2333%	$ 204,764	FF1 232.29(f)	(1)
18	Less ASC 740 Regulatory Liability (FAS 109)		$ 4,015,556	Plant	0.2333%	$ 9,368	FF1 278.1(f)	(1)
19	Total Other Regulatory Assets (line 15 16 17 - 18)		$ 91,373,566			$ 258,196		(2)
20	Dispatch Center Prepayments	A.1.g	$ 105,048,059	W&S	2.3877%	$ 2,508,233	FF1 111.57(c)	(1)
21	Dispatch Center Materials and Supplies	A.1.h	$ 28,541,503	Plant	0.2333%	$ 66,587	FF1 227.8(c) + 5(c) fn	(1)
22	Dispatch Center Related Cash Working Capital	A.1.i						
23	Dispatch Center Operation and Maintenance Expense		$ 3,271,123	WC	12.50%	$ 408,890	Sheet 4, Line 14(f)	(1)
24	Dispatch Center Related Administrative and General Expense		$ 3,255,860	WC	12.50%	$ 406,983	Sheet 4, Line 26(f)	(3)
25	Total Dispatch Center Related Cash Working Capital (line 22 23)		$ 6,526,983			$ 815,873		(3)
26	Account 282		$ 1,143,462,163	FF1 275.9(k)				
27	less amounts related to divestiture		$ -	FF1 275.4(k)				
28	Total Account 282 (line 25 26)		$ 1,143,462,163					

Notes:

Line	Description	Allocation Factor	Reference	Notes
29	Wages & Salary Allocation (W&S)	2.3877%	Sheet 6, Line 6(c)	(1)
30	Plant Allocation Allocation (Plant)	0.2333%	Sheet 6, Line 16(c)	(1)
31	Dispatch Center Transmission Plant Allocation Factor (T Plant)	0.8241%	Exhibit No. ES-223, Schedule 3, Page 6 of 6, Line 22(c)	(4)
32	Cash Working Capital (WC)	12.50%	OATT - Schedule 1, A.1.i	(1)

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Proposed revisions reflect the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset
(3) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses
(4) Proposed revisions reflect the addition of the Dispatch Center Transmission Plant Allocation Factor.

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated SCADA Revenue Requirement Under Changed Rates
Under Schedule 1, Appendix A
Expense Items For the Calendar year 2014
Sheet 4

Line	(a) Description	(b) Tariff Section	(c) Total	(d) Allocator	(e) Allocation Factor	(f) = (c) * (e) Dispatch Center Allocated	(g) Reference	(h) Notes
1	Dispatch Center Depreciation Expense	B						
2	Dispatch Center Plant Depreciation Expense					$ 276,720	See Line 31(d)	(1)
3	General Plant Depreciation Expense		$ 8,720,270	W&S	2.3877%	$ 208,214	FF1 336.10(b)	(1)
4	Total Dispatch Center Depreciation Expense (line 2 3)					$ 484,934		
5	Dispatch Center Related Amortization of Investment Tax Credits	C	$ (1,310,106)	Plant	0.2333%	$ (3,056)	FF1 266.8(f) & 11(f)	(1)
6	Dispatch Center Related Municipal Tax Expense	D	$ 120,588,821	Plant	0.2333%	$ 281,334	FF1 263.5(i)	(1)
7	Dispatch Center Related Payroll Tax Expense	E	$ 12,412,619	W&S	2.3877%	$ 296,376	FF1 263.10(i)	(1)
8	Dispatch Center Operations & Maintenance Expense	F						
9	Load dispatching #561		$ -	Direct	100.0000%	$ -	FF1 321.84(b)	(1)
10	Load dispatching - Reliability #561.1		$ 1,389,220	Direct	100.0000%	$ 1,389,220	FF1 321.85(b)	(1)
11	Load dispatching - Mon & Oper Trans System 561.2		$ 1,311,222	Direct	100.0000%	$ 1,311,222	FF1 321.86(b)	(1)
12	Load dispatching - Trans Service & Scheduling #561.3		$ 570,681	Direct	100.0000%	$ 570,681	FF1 321.87(b)	(1)
13	Scheduling, System Control and Dispatch Services #561.4		$ 12,155,295		0%	$ -	FF1 321.88(b)	(1)
14	Total Dispatch Center O&M Expense (sum of lines [9-13])		$ 15,426,418			$ 3,271,123		
15	Dispatch Center Related Administrative & General Expenses	G						
16	Administrative and General Expenses		$ 145,329,829				FF1 323.197(b)	(1)
17	less: Property Insurance (Acct #924)		$ 926,016				FF1 323.185(b)	(1)
18	less: Regulatory Commission Expenses (Acct #928)		$ 9,560,209				FF1 323.189(b)	(1)
19	less: General Advertising Expenses (Acct #930.1)		$ 32,018				FF1 323.191(b)	(1)
20	less: Miscellaneous General Expenses (Acct #930.2) '(a)		$ 52,118				FF1 323.192(b) fn	(1)
21	less: Merger-Related Costs		$ -					(2)
22	Subtotal (line 16 - sum of lines[17-21])		$ 134,759,468	W&S	2.3877%	$ 3,217,652		
23	Property Insurance		$ 926,016	Plant	0.2333%	$ 2,160	FF1 323.185(b)	(1)
24	FERC Assessments in Regulatory Commission Expenses (Acct #928)		$ 1,992,376	Plant	0.2333%	$ 4,648	FF1 350.7(d)	(1)
25	Transmission Merger-Related Costs		$ 3,810,195	T Plant	0.8241%	$ 31,400	Exhibit No. ES-220, Page 2 of 8, Line 2(B)	(2)
26	Total Dispatch Center Related A&G Expenses (sum of lines [22-25])		$ 141,488,055			$ 3,255,860		

NOTES:

Line	Description	Allocation Factor	Reference	Notes
27	Direct Allocation (Direct)	100.0000%		(1)
28	Wages & Salaries Allocation (W&S)	2.3877%	Sheet 6, Line 6(c)	(1)
29	Total Plant Allocation (Plant)	0.2333%	Sheet 6, Line 16(c)	(1)
30	Transmission Plant Allocation (T Plant)	0.8241%	Exhibit No. ES-223, Schedule 3, Page 6 of 6, Line 22(c)	(3)

Line	Description	Total Investment	Life Depr. Rate	Depreciation Expense	Reference	Notes
31	Mass. Ave. Service Center - 431 (Trans. Station Equipment)	$ 7,966,151	2.53%	$ 201,464	Sheet 6, Line 9(c)	(1)
32	SCADA Mass. Ave. - 421 (Trans. & Conversion Station Structures)	$ 2,816,142	2.19%	$ 61,646	Sheet 6, Line 10(c)	(1)
33	SCADA Mass. Ave. - 431 (Trans. Station Equipment)	$ 537,962	2.53%	$ 13,610	Sheet 6, Line 11(c)	(1)
34	Total	$ 11,320,255		$ 276,720	Sum Lines 31 thru 33	

(a) NSTAR Green Program costs are excludable for Transmission billing purposes. Reflects actual information per Eversource's accounting records.

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses
(3) Proposed revisions reflect the addition of the Dispatch Center Transmission Plant Allocation Factor.

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated SCADA Revenue Requirement Under Changed Rates
Under Schedule 1, Appendix A
Allocation Calculations For the Calendar year 2014
Sheet 6

	(a)	(b)		(c)	(d)	(e)
Line	Description	Tariff Section		Amount	Reference	Notes
1	Dispatch Center Wages & Salaries Allocation Factor	Definitions				
2	Direct Dispatch Center Wages & Salaries		$	2,858,118	Note (a)	(1)
3	NSTAR Electric Direct Wages & Salaries		$	152,023,518	FF1 354.28(b)	(1)
4	Less: Administrative & General Wages & Salaries		$	32,322,705	FF1 354.27(b)	(1)
5	Net NSTAR Electric Wages & Salaries (line 3 - 4)		$	119,700,813		
6	Wages & Salaries Allocation Factor (line 2 / 5)			2.3877%		
7	Dispatch Center Plant Allocation Factor	Definitions				
8	Investment In Dispatch Center Plant					
9	Mass. Ave. Service Center - 431 (Trans. Station Equipment)		$	7,966,151	Note (a)	(1)
10	SCADA Mass. Ave. - 421 (Trans. & Conversion Station Structures)		$	2,816,142		(1)
11	SCADA Mass. Ave. - 431 (Trans. Station Equipment)		$	537,962		(1)
12	Total Investment in Dispatch Center Plant (line 9 + 10 + 11)		$	11,320,255		
13	Dispatch Center Related General Plant		$	4,463,606	Sheet 3, Line 2(f)	(1)
14	Total Dispatch Center Plant Investment (line 12 + 13)		$	15,783,861		
15	Total Plant in Service		$	6,765,341,609	FF1 207.104(g)	(1)
16	Plant Allocation Factor (line 14 / 15)			0.2333%		
17	Dispatch Center Transmission Plant Allocation Factor	Definitions				(2)
18	Total Investment in Dispatch Center Plant (line 12)		$	11,320,255		
19	Dispatch Center Related General Plant (line 13)		$	4,463,606		
20	Total Dispatch Center Plant Investment (line 18 + 19)		$	15,783,861		
21	Total Investment in Transmission Plant		$	1,915,292,693	FF1 207.99(g)	
22	Dispatch Center Transmission Plant Allocation Factor (line 20 / 21)			0.8241%		(2)

Note (a): Reflects actual information per Eversource's accounting records.

Notes

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.

(2) The proposed revisions include the Dispatch Center Transmission Plant Allocation Factor

Exhibit No. ES-223
Schedule 4

SCADA Revenue Requirements under Changed Rates for the Calendar Year 2017

Eversource Energy Service Company

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated SCADA Revenue Requirement Under Changed Rates
Under Schedule 1, Appendix A
For the Calendar Year 2017

	(A)	(B)	(C)	
Line	**Description**	**Reference**	**Total NSTAR Electric**	
1	2014 Actual SCADA Revenue Requirement	Exh bit No. ES-223, Schedule 4, Page 2 of 6, Line 26(c)	$ 6,815,229	
2	Estimated 2015 SCADA Plant Additions	(1)	$ -	
3	Carrying Charge Factor (CCF)	(1)	0.00%	
4	2015 Incremental Estimated SCADA Revenue Requirement	Line 2 x 3	-	
5	Total Estimated SCADA Revenue Requirement for 2015	Line 1 + 4	$ 6,815,229	
6	Estimated 2016 SCADA Plant Additions	(1)	$ -	
7	Carrying Charge Factor (CCF)	(1)	0.00%	
8	2016 Incremental Estimated SCADA Revenue Requirement	Line 6 x 7	-	
9	Total Estimated SCADA Revenue Requirement for 2016	Line 5 + 8	$ 6,815,229	(2)

Notes:

(1) There is no forecasted SCADA plant.

(2) The revenue requirements calculations for the calendar year 2016 (including any forecast for 2016) are used as an estimate for the revenue requirements for 2017, which are used to calculate the revenue impact of the proposed cost recovery.

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated SCADA Revenue Requirement Under Changed Rates
Under Schedule 1, Appendix A
Total Revenue Requirements For the Calendar year 2014
Sheet 1

Line	(a) Description	(b) Tariff Section	(c) Amount	(d) Reference	(e) Notes
1	Dispatch Center Investment Base	A.1			
2	Dispatch Center Plant	A.1.a	$ 11,320,255	Sheet 3, Line 1(f)	(1)
3	Dispatch Center Related General Plant	A.1.b	$ 4,463,606	Sheet 3, Line 2(f)	(1)
4	Dispatch Center Plant Held for Future Use	A.1.c	$ -	Sheet 3, Line 3(f)	(1)
5	Total Plant (line 2 + 3 + 4)		$ 15,783,861		
6	Dispatch Center Related Depreciation Reserve	A.1.d	$ 6,017,455	Sheet 3, Line 7(f)	(1)
7	Dispatch Center Related Accumulated Deferred Taxes	A.1.e	$ 4,962,888	Sheet 3, Line 13(f)	(1)
8	Total Net Plant (line 5 - 6 - 7)		$ 4,803,518		
9	Other Regulatory Assets	A.1.f	$ 226,796	Sheet 3, Line 19(f)	(2)
10	Dispatch Center Prepayments	A.1.g	$ 2,508,233	Sheet 3, Line 20(f)	(1)
11	Disptach Center Materials & Supplies	A.1.h	$ 66,587	Sheet 3, Line 21(f)	(1)
12	Dispatch Center Related Cash Working Capital	A.1.i	$ 815,873	Sheet 3, Line 25(f)	(2)
13	Total Dispatch Center Investment Base (sum of lines [8-12])		$ 8,421,007		
14	Revenue Requirements				
15	Investment Return and Income Taxes	A.2	$ 1,046,461	Sheet 2, Line 38(c)	(2)
16	Disptach Center Depreciation Expense	B	$ 484,934	Sheet 4, Line 4(f)	(1)
17	Dispatch Center Related Amortization of Investment Tax Credits	C	$ (3,056)	Sheet 4, Line 5(f)	(1)
18	Dispatch Center Related Municipal Tax Expense	D	$ 281,334	Sheet 4, Line 6(f)	(1)
19	Dispatch Center Related Payroll Tax Expense	E	$ 296,376	Sheet 4, Line 7(f)	(1)
20	Dispatch Center Operation & Maintenance Expense	F	$ 3,271,123	Sheet 4, Line 14(f)	(1)
21	Dispatch Center Related Administrative and General Expenses	G	$ 3,255,860	Sheet 4, Line 26(f)	(2)
22	Total Revenue Requirements (sum of lines [15-21])		$ 8,633,032		
23	PTF Transmission Plant Allocator		82.4832%		(1)
24	PTF Revenue Requirement for SCADA (line 22 * 24)		$ 7,120,801		
25	PTF Transmission Plant Allocator		(305,572)	Exhibit 1	(1)
26	PTF Revenue Requirement for SCADA (line 22 * 24)		$ 6,815,229		

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.

(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated SCADA Revenue Requirement Under Changed Rates
Under Schedule 1, Appendix A
Investment Return and Income Tax Calculation For the Calendar year 2014
Sheet 2

Line	(a) Description	(b) Tariff Section	(c) Balance	(d) Capitalization Ratio	(e) Cost	(f) Weighted Cost	(g) Equity Cost	(h) Reference	(I) Notes
1	Weighted Cost of Capital	A.2.a							
2	Long Term Debt	A.2 a.i	$ 1,792,712,148	41.74%	4.22%	1.76%		Page 112.24(c)	(1)
3	Preferred Stock	A.2.a.ii	$ 43,000,000	1.00%	4.56%	0.05%	0.05%	Page 112.3(c)	(1)
4	Common Equity	A.2.a.iii	$ 2,459,452,736	57.26%	11.07%	6.34%	6.34%	Page 112.16(c) (less Line 3)	(1)
5	Total (line 2 + 3 + 4)		$ 4,295,164,884	100 00%		8.15%	6.39%		
6	Total Investment Base		$ 8,421,007					Sheet 1, Line 13(c)	(2)
7	Weighted Cost of Capital		8.15%					Line 5(f)	
8	Total Return on Investment		$ 686,312					Line 6 * Line 7	
9	Federal Income Tax	A 2.b							
10	A = Equity Cost		6.39%					Line 5(g)	
11	B = Transmission Amortization of ITC		$ (3,056)					Sheet 4, Line 5(f)	(1)
12	C = Equity AFUDC		$ 700						
13	Total B + C		$ (2,356)					Line 11 + Line 12	
14	D = Investment Base		$ 8,421,007					Line 6	
15	(B + C) / D		-0.0280%					Line 13 / Line 14	
16	(A + [(C + B) / D])		6.3620%					Line 10 + Line 15	
17	FT = Federal Income Tax Rate		35.00%						
18	1 - FT		65.00%					1 - Line 17	
19	Federal Tax Factor		3.4257%					Line 16 * Line 17 / Line 18	
20	Total Federal Income Taxes		$ 288,478					Line 14 * Line 19	
21	State Income Tax	A.2.c							
22	A = Equity Cost		6.39%					Line 5(g)	
23	B = Transmission Amortization of ITC		$ (3,056)					Sheet 4, Line 5(f)	(1)
24	C = Equity AFUDC		$ 700.00						
25	Total B + C		$ (2,356)					Line 23 + Line 24	
26	D = Investment Base		$ 8,421,007					Line 6	
27	(B + C) / D		-0.0280%					Line 25 / Line 26	
28	(A + [(C + B) / D])		6.3620%					Line 22 + Line 27	
29	ST = State Income Tax Rate		8.00%						
30	1 - ST		92.00%					1 - Line 29	
31	Federal Tax Factor		3.4257%					Line 19	
32	State Tax Factor		0.8511%					(Line 28 + Line 31) * Line 29 / Line 30	
33	Total State Income Taxes		$ 71,671					Line 26 * Line 32	
34	Investment Return and Income Taxes	A.2							
35	Return on Investment		$ 686,312					Line 8	
36	Federal Income Taxes		$ 288,478					Line 20	
37	State Income Taxes		$ 71,671					Line 33	
38	Total Investment Return and Income Taxes		$ 1,046,461					Sum Lines 35 thru 37	
39	Value of 50BP ROE Adder								
40	ROE Adder		0.50%					Per Tariff	
41	Equity Ratio		57.26%					Line 4(d)	
42	Effective Adder		0.29%					Line 40 * Line 41	
43	Tax Gross-up		0.1949%					Line 42 * .6722408	
44	Adder plus Gross-up		0.4849%					Line 42 + Line 43	
45	Rate Base		$ 8,421,007					Line 6	
46	Earned Adder		$ 40,833					Line 44 * Line 45	
47	PTF Ratio		82.4832%					RNS Sheet 6	(1)
48	PTF Related Adder		$ 33,680					Line 46 * Line 47	

Notes

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.

(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated SCADA Revenue Requirement Under Changed Rates
Under Schedule 1, Appendix A
Rate Base Items For the Calendar year 2014
Sheet 3

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Line	Description	Tariff Section	Total	Allocator	Allocation Factor	Dispatch Center Allocated	Reference	Notes
1	Dispatch Center Plant	A.1.a				$ 11,320,255	Sheet 6, Line 12(c)	(1)
2	Dispatch Center Related General Plant	A.1.b	$ 186,941,660	W&S	2.3877%	$ 4,463,606	FF1 207.99(g)	(1)
3	Dispatch Center Plant Held for Future Use	A.1.c				$ -	FF1 214	(1)
4	Dispatch Center Related Depreciation Reserve	A.1.d						
5	Dispatch Center Depreciation Reserve					$ 4,764,129	FF1 219.25(b) (part)	(1)
6	Transmission Related General Depreciation Reserve		$ 52,490,917	W&S	2.3877%	$ 1,253,326	FF1 219.28(b)	(1)
7	Total Dispatch Center Related Depreciation Reserve (line 5 6)					$ 6,017,455		
8	Dispatch Center Related Accumulated Deferred Taxes	A.1.e						
9	ADIT - Accelerated Amortization Property (Acct #281)		$ -	Plant	0.2333%	$ -	FF1 273.17(k)	(1)
10	ADIT - Other Property (Acct #282)		$ 1,143,462,163	Plant	0.2333%	$ 2,667,697	Line 27	(1)
11	ADIT - Other (Acct #283)					$ 2,876,873	Sheet 7, Line 30(d)	(1)
12	Less ADIT (Acct #190)					$ 581,682	Sheet 7, Line 12(d)	(1)
13	Total Dispatch Center Related ADIT (ine 9 10 11 - 12)					$ 4,962,888		
14	Other Regulatory Assets	A.1.f						
15	Unamortized balance of merger-related transmission costs		$ 3,810,195	Direct	0.8241%	$ 31,400	Exhibit No. ES-220, Page 2 of 8, Line 3(C)	(2)
16	FAS 106		$ -	W&S	2.3877%	$ -	FF1 232.1	(1)
17	ASC 740 Regulatory Asset (FAS 109)		$ 87,768,732	Plant	0.2333%	$ 204,764	FF1 232.29(f)	(1)
18	Less ASC 740 Regulatory Liability (FAS 109)		$ 4,015,556	Plant	0.2333%	$ 9,368	FF1 278.1(f)	(1)
19	Total Other Regulatory Assets (line 15 16 17 - 18)		$ 87,563,371			$ 226,796		(2)
20	Dispatch Center Prepayments	A.1.g	$ 105,048,059	W&S	2.3877%	$ 2,508,233	FF1 111.57(c)	(1)
21	Dispatch Center Materials and Supplies	A.1.h	$ 28,541,503	Plant	0.2333%	$ 66,587	FF1 227.8(c) + 5(c) fn	(1)
22	Dispatch Center Related Cash Working Capital	A.1.i						
23	Dispatch Center Operation and Maintenance Expense		$ 3,271,123	WC	12.50%	$ 408,890	Sheet 4, Line 14(f)	(1)
24	Dispatch Center Related Administrative and General Expense		$ 3,255,860	WC	12.50%	$ 406,983	Sheet 4, Line 26(f)	(3)
25	Total Dispatch Center Related Cash Working Capital (line 22 23)		$ 6,526,983			$ 815,873		(3)
26	Account 282		$ 1,143,462,163	FF1 275.9(k)				
27	less amounts related to divestiture		$ -	FF1 275.4(k)				
28	Total Account 282 (line 25 26)		$ 1,143,462,163					

Notes:

Line	Description	Allocation Factor	Reference	Notes
29	Wages & Salary Allocation (W&S)	2.3877%	Sheet 6, Line 6(c)	(1)
30	Plant Allocation Allocation (Plant)	0.2333%	Sheet 6, Line 16(c)	(1)
31	Dispatch Center Transmission Plant Allocation Factor (T Plant)	0.8241%	Exhibit No. ES-223, Schedule 4, Page 6 of 6, Line 22(c)	(4)
32	Cash Working Capital (WC)	12.50%	OATT - Schedule 1, A.1.i	(1)

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Proposed revisions reflect the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset
(3) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses
(4) Proposed revisions reflect the addition of the Dispatch Center Transmission Plant Allocation Factor.

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated SCADA Revenue Requirement Under Changed Rates
Under Schedule 1, Appendix A
Expense Items For the Calendar year 2014
Sheet 4

Line	(a) Description	(b) Tariff Section	(c) Total	(d) Allocator	(e) Allocation Factor	(f) (c) * (e) Dispatch Center Allocated	(g) Reference	(h) Notes
1	Dispatch Center Depreciation Expense	B						
2	Dispatch Center Plant Depreciation Expense					$ 276,720	See Line 31(d)	(1)
3	General Plant Depreciation Expense		$ 8,720,270	W&S	2.3877%	$ 208,214	FF1 336.10(b)	(1)
4	Total Dispatch Center Depreciation Expense (ine 2 3)					$ 484,934		
5	Dispatch Center Related Amortization of Investment Tax Credits	C	$ (1,310,106)	Plant	0.2333%	$ (3,056)	FF1 266.8(f) & 11(f)	(1)
6	Dispatch Center Related Municipal Tax Expense	D	$ 120,588,821	Plant	0.2333%	$ 281,334	FF1 263.5(i)	(1)
7	Dispatch Center Related Payroll Tax Expense	E	$ 12,412,619	W&S	2.3877%	$ 296,376	FF1 263.10(i)	(1)
8	Dispatch Center Operations & Maintenance Expense	F						
9	Load dispatching #561		$ -	Direct	100.0000%	$ -	FF1 321.84(b)	(1)
10	Load dispatching - Reliability #561.1		$ 1,389,220	Direct	100.0000%	$ 1,389,220	FF1 321.85(b)	(1)
11	Load dispatching - Mon & Oper Trans System 561.2		$ 1,311,222	Direct	100.0000%	$ 1,311,222	FF1 321.86(b)	(1)
12	Load dispatching - Trans Service & Scheduling #561.3		$ 570,681	Direct	100.0000%	$ 570,681	FF1 321.87(b)	(1)
13	Scheduling, System Control and Dispatch Services #561.4		$ 12,155,295		0%	$ -	FF1 321.88(b)	(1)
14	Total Dispatch Center O&M Expense (sum of lines [9-13])		$ 15,426,418			$ 3,271,123		
15	Dispatch Center Related Administrative & General Expenses	G						
16	Administrative and General Expenses		$ 145,329,829				FF1 323.197(b)	(1)
17	less Property Insurance (Acct #924)		$ 926,016				FF1 323.185(b)	(1)
18	less Regulatory Commission Expenses (Acct #928)		$ 9,560,209				FF1 323.189(b)	(1)
19	less General Advertising Expenses (Acct #930.1)		$ 32,018				FF1 323.191(b)	(1)
20	less Miscellaneous General Expenses (Acct #930.2) '(a)		$ 52,118				FF1 323.192(b) fn	(1)
21	less Merger-Related Costs		$ -					(2)
22	Subtotal (line 16 - sum of lines[17-21])		$ 134,759,468	W&S	2.3877%	$ 3,217,652		
23	Property Insurance		$ 926,016	Plant	0.2333%	$ 2,160	FF1 323.185(b)	(1)
24	FERC Assessments in Regulatory Commission Expenses (Acct #928)		$ 1,992,376	Plant	0.2333%	$ 4,648	FF1 350.7(d)	(1)
25	Transmission Merger-Related Costs		$ 3,810,195	T Plant	0.8241%	$ 31,400	Exhibit No. ES-220, Page 2 of 8, Line 2(C)	(2)
26	Total Dispatch Center Related A&G Expenses (sum of lines [22-25])		$ 141,488,055			$ 3,255,860		

NOTES:

Line	Description	Allocation Factor	Reference	Notes
27	Direct Allocation (Direct)	100.0000%		(1)
28	Wages & Salaries Allocation (W&S)	2.3877%	Sheet 6, Line 6(c)	(1)
29	Total Plant Allocation (Plant)	0.2333%	Sheet 6, Line 16(c)	(1)
30	Transmission Plant Allocation (T Plant)	0.8241%	Exhibit No. ES-223, Schedule 4, Page 6 of 6, Line 22(c)	(3)

Line	Description	Total Investment	Life Depr. Rate	Depreciation Expense	Reference	Notes
31	Mass. Ave. Service Center - 431 (Trans. Station Equipment)	$ 7,966,151	2.53%	$ 201,464	Sheet 6, Line 9(c)	(1)
32	SCADA Mass. Ave. - 421 (Trans. & Conversion Station Structures)	$ 2,816,142	2.19%	$ 61,646	Sheet 6, Line 10(c)	(1)
33	SCADA Mass. Ave. - 431 (Trans. Station Equipment)	$ 537,962	2.53%	$ 13,610	Sheet 6, Line 11(c)	(1)
34	Total	$ 11,320,255		$ 276,720	Sum Lines 31 thru 33	

(a) NSTAR Green Program costs are excludable for Transmission billing purposes. Reflects actual information per Eversource's accounting records.

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.
(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses
(3) Proposed revisions reflect the addition of the Dispatch Center Transmission Plant Allocation Factor.

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated SCADA Revenue Requirement Under Changed Rates
Under Schedule 1, Appendix A
Allocation Calculations For the Calendar year 2014
Sheet 6

	(a)	(b)		(c)	(d)	(e)
Line	Description	Tariff Section		Amount	Reference	Notes
1	Dispatch Center Wages & Salaries Allocation Factor	Definitions				
2	Direct Dispatch Center Wages & Salaries		$	2,858,118	Note (a)	(1)
3	NSTAR Electric Direct Wages & Salaries		$	152,023,518	FF1 354.28(b)	(1)
4	Less: Administrative & General Wages & Salaries		$	32,322,705	FF1 354.27(b)	(1)
5	Net NSTAR Electric Wages & Salaries (line 3 - 4)		$	119,700,813		
6	Wages & Salaries Allocation Factor (line 2 / 5)			2.3877%		
7	Dispatch Center Plant Allocation Factor	Definitions				
8	Investment In Dispatch Center Plant					
9	Mass. Ave. Service Center - 431 (Trans. Station Equipment)		$	7,966,151	Note (a)	(1)
10	SCADA Mass. Ave. - 421 (Trans. & Conversion Station Structures)		$	2,816,142	↓	(1)
11	SCADA Mass. Ave. - 431 (Trans. Station Equipment)		$	537,962		(1)
12	Total Investment in Dispatch Center Plant (line 9 + 10 + 11)		$	11,320,255		
13	Dispatch Center Related General Plant		$	4,463,606	Sheet 3, Line 2(f)	(1)
14	Total Dispatch Center Plant Investment (line 12 + 13)		$	15,783,861		
15	Total Plant in Service		$	6,765,341,609	FF1 207.104(g)	(1)
16	Plant Allocation Factor (line 14 / 15)			0.2333%		
17	Dispatch Center Transmission Plant Allocation Factor	Definitions				(2)
18	Total Investment in Dispatch Center Plant (line 12)		$	11,320,255		
19	Dispatch Center Related General Plant (line 13)		$	4,463,606		
20	Total Dispatch Center Plant Investment (line 18 + 19)		$	15,783,861		
21	Total Investment in Transmission Plant		$	1,915,292,693	FF1 207.99(g)	
22	Dispatch Center Transmission Plant Allocation Factor (line 20 / 21)			0.8241%		(2)

Note (a): Reflects actual information per Eversource's accounting records.

Notes

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.

(2) The proposed revisions include the Dispatch Center Transmission Plant Allocation Factor

Exhibit No. ES-223
Schedule 5

SCADA Revenue Requirements under Changed Rates for the Calendar Year 2018

Eversource Energy Service Company

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated SCADA Revenue Requirement Under Changed Rates
Under Schedule 1, Appendix A
For the Calendar Year 2018

	(A)	(B)	(C)
Line	**Description**	**Reference**	**Total NSTAR Electric**
1	2014 Actual SCADA Revenue Requirement	Exh bit No. ES-223, Schedule 5, Page 2 of 6, Line 26(c)	$ 6,812,004
2	Estimated 2015 SCADA Plant Additions	(1)	$ -
3	Carrying Charge Factor (CCF)	(1)	0.00%
4	2015 Incremental Estimated SCADA Revenue Requirement	Line 2 x 3	-
5	Total Estimated SCADA Revenue Requirement for 2015	Line 1 + 4	$ 6,812,004
6	Estimated 2016 SCADA Plant Additions	(1)	$ -
7	Carrying Charge Factor (CCF)	(1)	0.00%
8	2016 Incremental Estimated SCADA Revenue Requirement	Line 6 x 7	-
9	Total Estimated SCADA Revenue Requirement for 2016	Line 5 + 8	$ 6,812,004 (2)

Notes:

(1) There is no forecasted SCADA plant.

(2) The revenue requirements calculations for the calendar year 2016 (including any forecast for 2016) are used as an estimate for the revenue requirements for 2018, which are used to calculate the revenue impact of the proposed cost recovery.

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated SCADA Revenue Requirement Under Changed Rates
Under Schedule 1, Appendix A
Total Revenue Requirements For the Calendar year 2014
Sheet 1

Line	(a) Description	(b) Tariff Section	(c) Amount	(d) Reference	(e) Notes
1	Dispatch Center Investment Base	A.1			
2	Dispatch Center Plant	A.1.a	$ 11,320,255	Sheet 3, Line 1(f)	(1)
3	Dispatch Center Related General Plant	A.1.b	$ 4,463,606	Sheet 3, Line 2(f)	(1)
4	Dispatch Center Plant Held for Future Use	A.1.c	$ -	Sheet 3, Line 3(f)	(1)
5	Total Plant (line 2 + 3 + 4)		$ 15,783,861		
6	Dispatch Center Related Depreciation Reserve	A.1.d	$ 6,017,455	Sheet 3, Line 7(f)	(1)
7	Dispatch Center Related Accumulated Deferred Taxes	A.1.e	$ 4,962,888	Sheet 3, Line 13(f)	(1)
8	Total Net Plant (line 5 - 6 - 7)		$ 4,803,518		
9	Other Regulatory Assets	A.1.f	$ 195,396	Sheet 3, Line 19(f)	(2)
10	Dispatch Center Prepayments	A.1.g	$ 2,508,233	Sheet 3, Line 20(f)	(1)
11	Disptach Center Materials & Supplies	A.1.h	$ 66,587	Sheet 3, Line 21(f)	(1)
12	Dispatch Center Related Cash Working Capital	A.1.i	$ 815,873	Sheet 3, Line 25(f)	(2)
13	Total Dispatch Center Investment Base (sum of lines [8-12])		$ 8,389,607		
14	Revenue Requirements				
15	Investment Return and Income Taxes	A.2	$ 1,042,551	Sheet 2, Line 38(c)	(2)
16	Disptach Center Depreciation Expense	B	$ 484,934	Sheet 4, Line 4(f)	(1)
17	Dispatch Center Related Amortization of Investment Tax Credits	C	$ (3,056)	Sheet 4, Line 5(f)	(1)
18	Dispatch Center Related Municipal Tax Expense	D	$ 281,334	Sheet 4, Line 6(f)	(1)
19	Dispatch Center Related Payroll Tax Expense	E	$ 296,376	Sheet 4, Line 7(f)	(1)
20	Dispatch Center Operation & Maintenance Expense	F	$ 3,271,123	Sheet 4, Line 14(f)	(1)
21	Dispatch Center Related Administrative and General Expenses	G	$ 3,255,860	Sheet 4, Line 26(f)	(2)
22	Total Revenue Requirements (sum of lines [15-21])		$ 8,629,122		
23	PTF Transmission Plant Allocator		82.4832%		(1)
24	PTF Revenue Requirement for SCADA (line 22 * 24)		$ 7,117,576		
25	PTF Transmission Plant Allocator		(305,572)	Exhibit 1	(1)
26	PTF Revenue Requirement for SCADA (line 22 * 24)		$ 6,812,004		

Notes:

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(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated SCADA Revenue Requirement Under Changed Rates
Under Schedule 1, Appendix A
Investment Return and Income Tax Calculation For the Calendar year 2014
Sheet 2

Line	(a) Description	(b) Tariff Section	(c) Balance	(d) Capitalization Ratio	(e) Cost	(f) Weighted Cost	(g) Equity Cost	(h) Reference	(I) Notes
1	Weighted Cost of Capital	A.2.a							
2	Long Term Debt	A.2 a.i	$ 1,792,712,148	41.74%	4.22%	1.76%		Page 112.24(c)	(1)
3	Preferred Stock	A.2.a.ii	$ 43,000,000	1.00%	4.56%	0.05%	0.05%	Page 112.3(c)	(1)
4	Common Equity	A.2.a.iii	$ 2,459,452,736	57.26%	11.07%	6.34%	6.34%	Page 112.16(c) (less Line 3)	(1)
5	Total (line 2 + 3 + 4)		$ 4,295,164,884	100 00%		8.15%	6.39%		
6	Total Investment Base		$ 8,389,607					Sheet 1, Line 13(c)	(2)
7	Weighted Cost of Capital		8.15%					Line 5(f)	
8	Total Return on Investment		$ 683,753					Line 6 * Line 7	
9	Federal Income Tax	A 2.b							
10	A = Equity Cost		6.39%					Line 5(g)	
11	B = Transmission Amortization of ITC		$ (3,056)					Sheet 4, Line 5(f)	(1)
12	C = Equity AFUDC		$ 700						
13	Total B + C		$ (2,356)					Line 11 + Line 12	
14	D = Investment Base		$ 8,389,607					Line 6	
15	(B + C) / D		-0.0281%					Line 13 / Line 14	
16	(A + [(C + B) / D])		6.3619%					Line 10 + Line 15	
17	FT = Federal Income Tax Rate		35.00%						
18	1 - FT		65.00%					1 - Line 17	
19	Federal Tax Factor		3.4256%					Line 16 * Line 17 / Line 18	
20	Total Federal Income Taxes		$ 287,394					Line 14 * Line 19	
21	State Income Tax	A.2.c							
22	A = Equity Cost		6.39%					Line 5(g)	
23	B = Transmission Amortization of ITC		$ (3,056)					Sheet 4, Line 5(f)	(1)
24	C = Equity AFUDC		$ 700.00						
25	Total B + C		$ (2,356)					Line 23 + Line 24	
26	D = Investment Base		$ 8,389,607					Line 6	
27	(B + C) / D		-0.0281%					Line 25 / Line 26	
28	(A + [(C + B) / D])		6.3619%					Line 22 + Line 27	
29	ST = State Income Tax Rate		8.00%						
30	1 - ST		92.00%					1 - Line 29	
31	Federal Tax Factor		3.4256%					Line 19	
32	State Tax Factor		0.8511%					(Line 28 + Line 31) * Line 29 / Line 30	
33	Total State Income Taxes		$ 71,404					Line 26 * Line 32	
34	Investment Return and Income Taxes	A.2							
35	Return on Investment		$ 683,753					Line 8	
36	Federal Income Taxes		$ 287,394					Line 20	
37	State Income Taxes		$ 71,404					Line 33	
38	Total Investment Return and Income Taxes		$ 1,042,551					Sum Lines 35 thru 37	
39	Value of 50BP ROE Adder								
40	ROE Adder		0.50%					Per Tariff	
41	Equity Ratio		57.26%					Line 4(d)	
42	Effective Adder		0.29%					Line 40 * Line 41	
43	Tax Gross-up		0.1949%					Line 42 * .6722408	
44	Adder plus Gross-up		0.4849%					Line 42 + Line 43	
45	Rate Base		$ 8,389,607					Line 6	
46	Earned Adder		$ 40,681					Line 44 * Line 45	
47	PTF Ratio		82.4832%					RNS Sheet 6	(1)
48	PTF Related Adder		$ 33,555					Line 46 * Line 47	

Notes

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.

(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated SCADA Revenue Requirement Under Changed Rates
Under Schedule 1, Appendix A
Rate Base Items For the Calendar year 2014
Sheet 3

Line	(a) Description	(b) Tariff Section	(c) Total	(d) Allocator	(e) Allocation Factor	(f) Dispatch Center Allocated	(g) Reference	(h) Notes
1	Dispatch Center Plant	A.1.a				$ 11,320,255	Sheet 6, Line 12(c)	(1)
2	Dispatch Center Related General Plant	A.1.b	$ 186,941,660	W&S	2.3877%	$ 4,463,606	FF1 207.99(g)	(1)
3	Dispatch Center Plant Held for Future Use	A.1.c				$ -	FF1 214	(1)
4	Dispatch Center Related Depreciation Reserve	A.1.d						
5	Dispatch Center Depreciation Reserve					$ 4,764,129	FF1 219.25(b) (part)	(1)
6	Transmission Related General Depreciation Reserve		$ 52,490,917	W&S	2.3877%	$ 1,253,326	FF1 219.28(b)	(1)
7	Total Dispatch Center Related Depreciation Reserve (line 5 6)					$ 6,017,455		
8	Dispatch Center Related Accumulated Deferred Taxes	A.1.e						
9	ADIT - Accelerated Amortization Property (Acct #281)		$ -	Plant	0.2333%	$ -	FF1 273.17(k)	(1)
10	ADIT - Other Property (Acct #282)		$ 1,143,462,163	Plant	0.2333%	$ 2,667,697	Line 27	(1)
11	ADIT - Other (Acct #283)					$ 2,876,873	Sheet 7, Line 30(d)	(1)
12	Less ADIT (Acct #190)					$ 581,682	Sheet 7, Line 12(d)	(1)
13	Total Dispatch Center Related ADIT (ine 9 10 11 - 12)					$ 4,962,888		
14	Other Regulatory Assets	A.1.f						
15	Unamortized balance of merger-related transmission costs		$ -	Direct	0.8241%	$ -	Exhibit No. ES-220, Page 2 of 8, Line 3(D)	(2)
16	FAS 106		$ -	W&S	2.3877%	$ -	FF1 232.1	(1)
17	ASC 740 Regulatory Asset (FAS 109)		$ 87,768,732	Plant	0.2333%	$ 204,764	FF1 232.29(f)	(1)
18	Less ASC 740 Regulatory Liability (FAS 109)		$ 4,015,556	Plant	0.2333%	$ 9,368	FF1 278.1(f)	(1)
19	Total Other Regulatory Assets (line 15 16 17 - 18)		$ 83,753,176			$ 195,396		(2)
20	Dispatch Center Prepayments	A.1.g	$ 105,048,059	W&S	2.3877%	$ 2,508,233	FF1 111.57(c)	(1)
21	Dispatch Center Materials and Supplies	A.1.h	$ 28,541,503	Plant	0.2333%	$ 66,587	FF1 227.8(c) + 5(c) fn	(1)
22	Dispatch Center Related Cash Working Capital	A.1.i						
23	Dispatch Center Operation and Maintenance Expense		$ 3,271,123	WC	12.50%	$ 408,890	Sheet 4, Line 14(f)	(1)
24	Dispatch Center Related Administrative and General Expense		$ 3,255,860	WC	12.50%	$ 406,983	Sheet 4, Line 26(f)	(3)
25	Total Dispatch Center Related Cash Working Capital (line 22 23)		$ 6,526,983			$ 815,873		(3)
26	Account 282		$ 1,143,462,163	FF1 275.9(k)				
27	less amounts related to divestiture		$ -	FF1 275.4(k)				
28	Total Account 282 (line 25 26)		$ 1,143,462,163					

Notes:

Line	Description	Allocation Factor	Reference	Notes
29	Wages & Salary Allocation (W&S)	2.3877%	Sheet 6, Line 6(c)	(1)
30	Plant Allocation Allocation (Plant)	0.2333%	Sheet 6, Line 16(c)	(1)
31	Dispatch Center Transmission Plant Allocation Factor (T Plant)	0.8241%	Exhibit No. ES-223, Schedule 5, Page 6 of 6, Line 22(c)	(4)
32	Cash Working Capital (WC)	12.50%	OATT - Schedule 1, A.1.i	(1)

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.

(2) Proposed revisions reflect the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

(3) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

(4) Proposed revisions reflect the addition of the Dispatch Center Transmission Plant Allocation Factor.

Line	(a) Description	(b) Tariff Section	(c) Total	(d) Allocator	(e) Allocation Factor	(f) (c) * (e) Dispatch Center Allocated	(g) Reference	(h) Notes
1	Dispatch Center Depreciation Expense	B						
2	Dispatch Center Plant Depreciation Expense					$ 276,720	See Line 31(d)	(1)
3	General Plant Depreciation Expense		$ 8,720,270	W&S	2.3877%	$ 208,214	FF1 336.10(b)	(1)
4	Total Dispatch Center Depreciation Expense (ine 2 3)					$ 484,934		
5	Dispatch Center Related Amortization of Investment Tax Credits	C	$ (1,310,106)	Plant	0.2333%	$ (3,056)	FF1 266.8(f) & 11(f)	(1)
6	Dispatch Center Related Municipal Tax Expense	D	$ 120,588,821	Plant	0.2333%	$ 281,334	FF1 263.5(i)	(1)
7	Dispatch Center Related Payroll Tax Expense	E	$ 12,412,619	W&S	2.3877%	$ 296,376	FF1 263.10(i)	(1)
8	Dispatch Center Operations & Maintenance Expense	F						
9	Load dispatching #561		$ -	Direct	100.0000%	$ -	FF1 321.84(b)	(1)
10	Load dispatching - Reliability #561.1		$ 1,389,220	Direct	100.0000%	$ 1,389,220	FF1 321.85(b)	(1)
11	Load dispatching - Mon & Oper Trans System 561.2		$ 1,311,222	Direct	100.0000%	$ 1,311,222	FF1 321.86(b)	(1)
12	Load dispatching - Trans Service & Scheduling #561.3		$ 570,681	Direct	100.0000%	$ 570,681	FF1 321.87(b)	(1)
13	Scheduling, System Control and Dispatch Services #561.4		$ 12,155,295		0%	$ -	FF1 321.88(b)	(1)
14	Total Dispatch Center O&M Expense (sum of lines [9-13])		$ 15,426,418			$ 3,271,123		
15	Dispatch Center Related Administrative & General Expenses	G						
16	Administrative and General Expenses		$ 145,329,829				FF1 323.197(b)	(1)
17	less Property Insurance (Acct #924)		$ 926,016				FF1 323.185(b)	(1)
18	less Regulatory Commission Expenses (Acct #928)		$ 9,560,209				FF1 323.189(b)	(1)
19	less General Advertising Expenses (Acct #930.1)		$ 32,018				FF1 323.191(b)	(1)
20	less Miscellaneous General Expenses (Acct #930.2) '(a)		$ 52,118				FF1 323.192(b) fn	(1)
21	less Merger-Related Costs		$ -					(2)
22	Subtotal (line 16 - sum of lines[17-21])		$ 134,759,468	W&S	2.3877%	$ 3,217,652		
23	Property Insurance		$ 926,016	Plant	0.2333%	$ 2,160	FF1 323.185(b)	(1)
24	FERC Assessments in Regulatory Commission Expenses (Acct #928)		$ 1,992,376	Plant	0.2333%	$ 4,648	FF1 350.7(d)	(1)
25	Transmission Merger-Related Costs		$ 3,810,195	T Plant	0.8241%	$ 31,400	Exhibit No. ES-220, Page 2 of 8, Line 2(D)	(2)
26	Total Dispatch Center Related A&G Expenses (sum of lines [22-25])		$ 141,488,055			$ 3,255,860		

NOTES:

Line	Description	Allocation Factor	Reference	Notes
27	Direct Allocation (Direct)	100.0000%		(1)
28	Wages & Salaries Allocation (W&S)	2.3877%	Sheet 6, Line 6(c)	(1)
29	Total Plant Allocation (Plant)	0.2333%	Sheet 6, Line 16(c)	(1)
30	Transmission Plant Allocation (T Plant)	0.8241%	Exhibit No. ES-223, Schedule 5, Page 6 of 6, Line 22(c)	(3)

Line	Description	Total Investment	Life Depr. Rate	Depreciation Expense	Reference	Notes
31	Mass. Ave. Service Center - 431 (Trans. Station Equipment)	$ 7,966,151	2.53%	$ 201,464	Sheet 6, Line 9(c)	(1)
32	SCADA Mass. Ave. - 421 (Trans. & Conversion Station Structures)	$ 2,816,142	2.19%	$ 61,646	Sheet 6, Line 10(c)	(1)
33	SCADA Mass. Ave. - 431 (Trans. Station Equipment)	$ 537,962	2.53%	$ 13,610	Sheet 6, Line 11(c)	(1)
34	Total	$ 11,320,255		$ 276,720	Sum Lines 31 thru 33	

(a) NSTAR Green Program costs are excludable for Transmission billing purposes. Reflects actual information per Eversource's accounting records.

Notes:

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.

(2) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

(3) Proposed revisions reflect the addition of the Dispatch Center Transmission Plant Allocation Factor.

Line	(a) Description	(b) Tariff Section	(c) Amount	(d) Reference	(e) Notes
1	Dispatch Center Wages & Salaries Allocation Factor	Definitions			
2	Direct Dispatch Center Wages & Salaries		$ 2,858,118	Note (a)	(1)
3	NSTAR Electric Direct Wages & Salaries		$ 152,023,518	FF1 354.28(b)	(1)
4	Less: Administrative & General Wages & Salaries		$ 32,322,705	FF1 354.27(b)	(1)
5	Net NSTAR Electric Wages & Salaries (line 3 - 4)		$ 119,700,813		
6	Wages & Salaries Allocation Factor (line 2 / 5)		2.3877%		
7	Dispatch Center Plant Allocation Factor	Definitions			
8	Investment In Dispatch Center Plant				
9	Mass. Ave. Service Center - 431 (Trans. Station Equipment)		$ 7,966,151	Note (a)	(1)
10	SCADA Mass. Ave. - 421 (Trans. & Conversion Station Structures)		$ 2,816,142	↓	(1)
11	SCADA Mass. Ave. - 431 (Trans. Station Equipment)		$ 537,962		(1)
12	Total Investment in Dispatch Center Plant (line 9 + 10 + 11)		$ 11,320,255		
13	Dispatch Center Related General Plant		$ 4,463,606	Sheet 3, Line 2(f)	(1)
14	Total Dispatch Center Plant Investment (line 12 + 13)		$ 15,783,861		
15	Total Plant in Service		$ 6,765,341,609	FF1 207.104(g)	(1)
16	Plant Allocation Factor (line 14 / 15)		0.2333%		
17	Dispatch Center Transmission Plant Allocation Factor	Definitions			(2)
18	Total Investment in Dispatch Center Plant (line 12)		$ 11,320,255		
19	Dispatch Center Related General Plant (line 13)		$ 4,463,606		
20	Total Dispatch Center Plant Investment (line 18 + 19)		$ 15,783,861		
21	Total Investment in Transmission Plant		$ 1,915,292,693	FF1 207.99(g)	
22	Dispatch Center Transmission Plant Allocation Factor (line 20 / 21)		0.8241%		(2)

Note (a): Reflects actual information per Eversource's accounting records.

Notes

(1) Source of information is the PTO AC Annual Informational Filing submitted to FERC on July 31, 2015 under Docket No. RT04-2-000.

(2) The proposed revisions include the Dispatch Center Transmission Plant Allocation Factor

Exhibit No. ES-224
Schedule 1

Summary of Impact on Category A Revenue Requirements under Attachment ES-H, Schedule 21-ES to ISO-NE OATT (3-year amortization)

Eversource Energy Service Company

CL&P, PSNH, and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Comparison Under Present and Changed Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For the Calendar Year 2016-2018

Line	(A) Description	(B) Net Revenue Requirements under the Present Rates in Attachment ES-H	(C) Net Revenue Requirements under the Changed Rates in Attachment ES-H	(D) = (C) - (B) Difference (7) (Rounded to '000s)	(E) = (D) / (B) % Difference
1	2016 Estimated Schedule ES-H Revenue Requirement	$ 58,607,159 (1)	$ 58,172,458 (4)	$ (435,000) (a)	-0.74%
2	2017 Estimated Schedule ES-H Revenue Requirement	$ 58,607,159 (2)	$ 59,991,304 (5)	$ 1,384,000	2.36%
3	2018 Estimated Schedule ES-H Revenue Requirement	$ 58,607,159 (3)	$ 59,912,770 (6)	$ 1,306,000	2.23%

Notes:
(1) Exhibit No. ES-224, Schedule 1, Page 2 of 4, Line 5(B)
(2) Exhibit No. ES-224, Schedule 1, Page 3 of 4, Line 5(B)
(3) Exhibit No. ES-224, Schedule 1, Page 4 of 4, Line 5(B)
(4) Exhibit No. ES-224, Schedule 1, Page 2 of 4, Line 5(C)
(5) Exhibit No. ES-224, Schedule 1, Page 3 of 4, Line 5(C)
(6) Exhibit No. ES-224, Schedule 1, Page 4 of 4, Line 5(C)
(7) In connection with the three-year amortization alternative (with the proposed effective date of June 1, 2016), Eversource is showing the revenue impact for the thirty-six month period June 1, 2016 through May 31, 2019. Eversource is using calendar year revenue requirement calculations as estimates for the thirty-six month period beginning June 1, 2016. See Cooper Testimony Exhibit No. ES-200.

	2016	2017	2018	2019	Total
The amounts for each year are as follows:	$ (254,000)	$ 626,000	$ 1,338,000	$ 544,000	$ 2,254,000

(a) The 2016 estimated Schedule ES-H revenue requirement is negative because RNS revenues are shown for the calendar year consistent with ES-221. Actual RNS revenues are billed June - May

CL&P, PSNH, and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Comparison Under Present and Changed Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For the Calendar Year 2016

	(A)	(B)		(C)	
Line	Description	Net Revenue Requirements under the Present Rates in Attachment ES-H		Net Revenue Requirements under the Changed Rates in Attachment ES-H	
1	Total Schedule 21-ES Revenue Requirements	$ 835,176,268	(2)	$ 847,067,460	(3)
2	Regional Network Service (RNS) Revenue Credits	$ 730,092,671	(4)	$ 741,897,720	(5)
3	Localized Revenues Credits	$ 34,370,344	(1)	$ 34,891,188	(6)
4	Other Revenue Credits	$ 12,106,094	(1)	$ 12,106,094	(1)
5	Net Local Network Service Revenue Requirements *(Line 1 - 2 - 3 - 4)*	$ 58,607,159		$ 58,172,458	

Notes

(1) Support was filed as part of ES's Regulatory Oversight Filing with State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(2) Exhibit No. ES-224, Schedule 2, Page 1 of 7, Line 10(F)
(3) Exhibit No. ES-224, Schedule 3, Page 1 of 7, Line 10(F)

(4)

Line	Description	Amount		Reference
6	2014 RNS Revenue Credits under Present Rates	$ 618,194,635		(1)
7	Plus: 2015 Forecasted Incremental Estimated PTF Revenue Credits	73,137,000		Exhibit No. ES-221, Schedule 3, Page 1 of 20, Line 4(f)
8	Plus: 2016 Forecasted Incremental Estimated PTF Revenue Credits	42,053,500		Exhibit No. ES-221, Schedule 3, Page 1 of 20, Line 9(f)
9	Less: 2015 Impact on RNS Revenue Credits due to 50 basis points	2,094,516		(a)
10	Less: 2016 Impact on RNS Revenue Credits due to 50 basis points	1,197,948		(a)
11	2016 RNS Revenue Credits under Present Rates (Lines 6 + 7 + 8 - 9 - 10)	$ 730,092,671	To Line 2(B)	

(5)

Line	Description	Amount		Reference
12	RNS Revenue Credits under Present Rates	$ 730,092,671		Line 2(B)
13	Plus: Incremental Estimated PTF Revenue Requirements	11,893,000		Exhibit No. ES-221, Schedule 1, Page 1 of 1, Line 1(D)
14	Less: Impact on RNS Revenue Credits due to 50 basis points	87,951		Exhibit No. ES-221, Schedule 3, Pages 8, 13 & 18 of 20, Lines 15(B) **Less** Exhibit No. ES-221, Schedule 2, Pages 8, 13 & 18 of 20, Lines 15(B)
15	RNS Rev. Credits under Changed Rates (Lines 12 + 13 -14)	$ 741,897,720	To Line 2(C)	

(6)

Line	Description	Amount		Reference
16	Localized Revenue Credits under Present Rates	$ 34,370,344		Line 3(B)
17	Plus: Incremental Estimated PTF Revenue Requirements	523,000		Exhibit No. ES-226, Schedule 1, Page 1 of 1, Line 1(D)
18	Less: Impact on Localized Revenue Credits due to 50 basis points	2,156		Exhibit No. ES-226, Schedule 3, Pages 5, 10 & 15, 20, and 25 of 26, Lines 15(B) **Less** Exhibit No. ES-226, Schedule 2, Pages 5, 10 & 15, 20, and 25 of 26, Lines 15(B)
19	Localized Rev. Credits under Changed Rates (Lines 16+17-18)	$ 34,891,188	To Line 3(C)	

(a)

Line	Description	2015	All References below come from Exhibit No. ES-221 Schedule 2	2016	All References below come from Exhibit No. ES-221 Schedule 2
20	CL&P PTF Plant Additions	$ 276,000,000	Page 1 of 20, Line 2(C)	$ 68,000,000	Page 1 of 20, Line 7(C)
21	CL&P Cost of Capital Rate for 50bp Incentive	0.4396%	Page 8 of 20, Line 12(B)	0.4396%	Page 8 of 20, Line 12(B)
22	CL&P Subtotal (Lines 20 x 21)	$ 1,213,296		$ 298,928	
23	PSNH PTF Plant Additions	$ 114,000,000	Page 1 of 20, Line 2(D)	$ 117,000,000	Page 1 of 20, Line 7(D)
24	PSNH Cost of Capital Rate for 50bp Incentive	0.4540%	Page 13 of 20, Line 12(B)	0.4540%	Page 13 of 20, Line 12(B)
25	PSNH Subtotal (Lines 23 x 24)	$ 517,560		$ 531,180	
26	WMECO PTF Plant Additions	$ 87,000,000	Page 1 of 20, Line 2(E)	$ 88,000,000	Page 1 of 20, Line 7(E)
27	WMECO Cost of Capital Rate for 50bp Incentive	0.4180%	Page 18 of 20, Line 12(B)	0.4180%	Page 18 of 20, Line 12(B)
28	WMECO Subtotal (Lines 26 x 27)	$ 363,660		$ 367,840	
29	**Total** (Lines 22 + 25 +28)	$ 2,094,516	To Line 9(B)	$ 1,197,948	To Line 10(B)

CL&P, PSNH, and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Comparison Under Present and Changed Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For the Calendar Year 2017

	(A)	(B)			(C)		
Line	**Description**	**Net Revenue Requirements under the Present Rates in Attachment ES-H**			**Net Revenue Requirements under the Changed Rates in Attachment ES-H**		
1	Total Schedule 21-ES Revenue Requirements	$	835,176,268	(2)	$	847,811,526	(3)
2	Regional Network Service (RNS) Revenue Credits	$	730,092,671	(4)	$	740,792,110	(5)
3	Localized Revenues Credits	$	34,370,344	(1)	$	34,922,018	(6)
4	Other Revenue Credits	$	12,106,094	(1)	$	12,106,094	(1)
5	Net Local Network Service Revenue Requirements *(Line 1 - 2 - 3 - 4)*	$	58,607,159		$	59,991,304	

Notes
(1) Support was filed as part of ES's Regulatory Oversight Filing with State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(2) Exhibit No. ES-224, Schedule 2, Page 1 of 7, Line 10(F)
(3) Exhibit No. ES-224, Schedule 3, Page 1 of 7, Line 10(F)

(4)

Line	Description		Amount		Source
6	2014 RNS Revenue Credits under Present Rates	$	618,194,635		(1)
7	Plus: 2015 Forecasted Incremental Estimated PTF Revenue Credits		73,137,000		Exhibit No. ES-221, Schedule 4, Page 1 of 20, Line 4(f)
8	Plus: 2016 Forecasted Incremental Estimated PTF Revenue Credits		42,053,500		Exhibit No. ES-221, Schedule 4, Page 1 of 20, Line 9(f)
9	Less: 2015 Impact on RNS Revenue Credits due to 50 basis points		2,094,516		Exhibit No. 224, Schedule 1, Page 3 of 4, Line 29(B)
10	Less: 2016 Impact on RNS Revenue Credits due to 50 basis points		1,197,948		Exhibit No. 224, Schedule 1, Page 3 of 4, Line 29(C)
11	2016 RNS Revenue Credits under Present Rates (Lines 6 + 7 + 8 - 9 - 10)	$	730,092,671	To Line 2(B)	

(5)

Line	Description		Amount		Source
12	RNS Revenue Credits under Present Rates	$	730,092,671		Line 2(B)
13	Plus: Incremental Estimated PTF Revenue Requirements		10,746,000		Exhibit No. ES-221, Schedule 1, Page 1 of 1, Line 2(D)
14	Less: Impact on RNS Revenue Credits due to 50 basis points		46,561		Exhibit No. ES-221, Schedule 4, Pages 8, 13 & 18 of 20, Lines 15(B) **Less** Exhibit No. ES-221, Schedule 2, Pages 8, 13 & 18 of 20, Lines 15(B)
15	RNS Rev. Credits under Changed Rates (Lines 12 + 13 -14)	$	740,792,110	To Line 2(C)	

(6)

Line	Description		Amount		Source
16	Localized Revenue Credits under Present Rates	$	34,370,344		Line 3(B)
17	Plus: Incremental Estimated PTF Revenue Requirements		555,000		Exhibit No. ES-226, Schedule 1, Page 1 of 1, Line 2(D)
18	Less: Impact on Localized Revenue Credits due to 50 basis points		3,326		Exhibit No. ES-226, Schedule 4, Pages 5, 10 & 15, 20, and 25 of 26, Lines 15(B) **Less** Exhibit No. ES-226, Schedule 2, Pages 5, 10 & 15, 20, and 25 of 26, Lines 15(B)
19	Localized Rev. Credits under Changed Rates (Lines 16+17-18)	$	34 922 018	To Line 3(C)	

CL&P, PSNH, and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Comparison Under Present and Changed Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For the Calendar Year 2018

	(A)	(B)			(C)		
Line	**Description**	**Net Revenue Requirements under the Present Rates in Attachment ES-H**			**Net Revenue Requirements under the Changed Rates in Attachment ES-H**		
1	Total Schedule 21-ES Revenue Requirements	$	835,176,268	(2)	$	846,573,407	(3)
2	Regional Network Service (RNS) Revenue Credits	$	730,092,671	(4)	$	739,686,497	(5)
3	Localized Revenues Credits	$	34,370,344	(1)	$	34,868,046	(6)
4	Other Revenue Credits	$	12,106,094	(1)	$	12,106,094	(1)
5	Net Local Network Service Revenue Requirements *(Line 1 - 2 - 3 - 4)*	$	58,607,159		$	59,912,770	

Notes
(1) Support was filed as part of ES's Regulatory Oversight Filing with State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(2) Exhibit No. ES-224, Schedule 2, Page 1 of 7, Line 10(F)
(3) Exhibit No. ES-224, Schedule 3, Page 1 of 7, Line 10(F)

(4)

6	2014 RNS Revenue Credits under Present Rates	$	618,194,635		(1)
7	Plus: 2015 Forecasted Incremental Estimated PTF Revenue Credits		73,137,000		Exhibit No. ES-221, Schedule 5, Page 1 of 20, Line 4(f)
8	Plus: 2016 Forecasted Incremental Estimated PTF Revenue Credits		42,053,500		Exhibit No. ES-221, Schedule 5, Page 1 of 20, Line 9(f)
9	Less: 2015 Impact on RNS Revenue Credits due to 50 basis points		2,094,516		Exhibit No. 224, Schedule 1, Page 3 of 4, Line 29(B)
10	Less: 2016 Impact on RNS Revenue Credits due to 50 basis points		1,197,948		Exhibit No. 224, Schedule 1, Page 3 of 4, Line 29(C)
11	2016 RNS Revenue Credits under Present Rates (Lines 6 + 7 + 8 - 9 - 10)	$	730,092,671	To Line 2(B)	

(5)

12	RNS Revenue Credits under Present Rates	$	730,092,671		Line 2(B)
13	Plus: Incremental Estimated PTF Revenue Requirements		9,599,000		Exhibit No. ES-221, Schedule 1, Page 1 of 1, Line 3(D)
14	Less: Impact on RNS Revenue Credits due to 50 basis points		5,174		Exhibit No. ES-221, Schedule 5, Pages 8, 13 & 18 of 20, Lines 15(B) **Less** Exhibit No. ES-221, Schedule 2, Pages 8, 13 & 18 of 20, Lines 15(B)
15	RNS Rev. Credits under Changed Rates (Lines 12 + 13 -14)	$	739,686,497	To Line 2(C)	

(6)

16	Localized Revenue Credits under Present Rates	$	34,370,344		Line 3(B)
17	Plus: Incremental Estimated PTF Revenue Requirements		499,000		Exhibit No. ES-226, Schedule 1, Page 1 of 1, Line 3(D)
18	Less: Impact on Localized Revenue Credits due to 50 basis points		1,298		Exhibit No. ES-226, Schedule 5, Pages 5, 10 & 15, 20, and 25 of 26, Lines 15(B) **Less** Exhibit No. ES-226, Schedule 3, Pages 5, 10 & 15, 20, and 25 of 26, Lines 15(B)
19	Localized Rev. Credits under Changed Rates (Lines 16+17-18)	$	34 868 046	To Line 3(C)	

Exhibit No. ES-224
Schedule 2

Category A Revenue Requirements under the Present Rates

Eversource Energy Service Company

CL&P, PSNH, and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Under Present Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For the Calendar Years 2016 - 2018

	(A)	(B)	(C)	(D)	(E)	(F)=(C)+(D)+(E)
Line	**Description**	**Reference**	**CL&P**	**PSNH**	**WMECO**	**Total NU**
1	2014 Actual Schedule 21-ES, Category A Revenue Requirement		$ 477,229,327 (1)	$ 112,110,056 (2)	$ 116,984,685 (3)	$ 706,324,068
2	Estimated 2015 Schedule 21-ES, Category A Plant Additions	(4)	$ 278,000,000	$ 123,000,000	$ 100,000,000	$ 501,000,000
3	Carrying Charge Factor (CCF)	Exhibit No. ES-224, Schedule 2, Page 2 of 7, Note (c)	15.70%	17.29%	14.16%	15.78%
4	2015 Incremental Estimated Schedule 21-ES, Category A Revenue Requirement	Line 2 x 3	43,646,000	21,266,700	14,160,000	79,072,700
5	2015 Incremental Estimated Schedule 21-ES, Category A CWIP Revenue Requirements	(4)	$ 6,218,000	$ -	$ (999,000)	$ 5,219,000
6	Total Estimated Schedule 21-ES, Category A Revenue Requirement for 2015	Line 1 + 4 + 5	$ 527,093,327	$ 133,376,756	$ 130,145,685	$ 790,615,768
7	Estimated 2016 Schedule 21-ES, Category A Plant Additions	(4)	$ 72,000,000	$ 117,000,000	$ 92,000,000	$ 281,000,000
8	Carrying Charge Factor (CCF)	Line 3	15.70%	17.29%	14.16%	15.86%
9	2016 Incremental Estimated Schedule 21-ES, Category A Revenue Requirement	Line 7 x 8	11,304,000	20,229,300	13,027,200	44,560,500
10	Total Estimated Schedule 21-ES, Category A Revenue Requirement for 2016	Line 6 + 9 + 10	$ 538,397,327	$ 153,606,056	$ 143,172,885	$ 835,176,268 (5)

Notes:
(1) Exhibit No. ES-224, Schedule 2, Page 2 of 7, Line 29(C)
(2) Exhibit No. ES-224, Schedule 2, Page 2 of 7, Line 29(D)
(3) Exhibit No. ES-224, Schedule 2, Page 2 of 7, Line 29(E)
(4) Based on Eversource's Forecast
(5) The revenue requirements calculations for the calendar year 2016 (including any forecast for 2016) are used as an estimate for the revenue requirements for 2017 and 2018, which are used to calculate the revenue impact of the proposed cost recovery.

CL&P, PSNH, and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Comparison Under Present Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For Costs in 2014
Sheet 2a

	(A)	(B) Attachment H Reference	(C)	(D)	(E)	(F)	(G)	
Line	I. INVESTMENT BASE	Section:	CL&P	PSNH	WMECO	Total	Source	Notes
1	Transmission Plant	II(A)(1)(a)	2,977,569,726	648,561,975	829,609,658	4,455,741,359	Sheet 3	(a)
2	General Plant	II(A)(1)(b)	86,941,769	58,369,540	18,348,753	163,660,062	Sheet 3	(a)
3	Plant Held For Future Use	II(A)(1)(c)	35,612,990	13,626,119	750,000	49,989,109	Sheet 3	(a)
4	Total Plant (Lines 1+2+3)		3,100,124,485	720,557,634	848,708,411	4,669,390,530		
5	Accumulated Depreciation	II(A)(1)(e)	603,780,016	132,512,720	51,920,388	788,213,124	Sheet 3	(a)
6	Accumulated Deferred Income Taxes	II(A)(1)(f)	391,238,076	123,116,055	201,101,631	715,455,762	Sheet 3	(a)
7	Loss On Reacquired Debt	II(A)(1)(g)	5,711,371	2,107,937	355,953	8,175,261	Sheet 3	(a)
8	Other Regulatory Assets	II(A)(1)(h)	18,536,117	8,385,129	6,105,712	33,026,958	Sheet 3	(b)
9	Net Investment (Line 4-5-6+7+8)		2,129,353,881	475,421,925	602,148,057	3,206,923,863		(b)
10	Prepayments	II(A)(1)(j)	19,487,085	4,911,873	642,737	25,041,695	Sheet 3	(a)
11	Materials & Supplies	II(A)(1)(k)	36,123,136	10,822,161	3,067,304	50,012,601	Sheet 3	(a)
12	Cash Working Capital	II(A)(1)(l)	9,104,674	2,502,459	1,752,501	13,359,634	Sheet 3	(b)
13	Sub Total (Line 10+11+12)		64,714,895	18,236,493	5,462,542	88,413,930		
14	Total Investment Base Excluding CWIP (Lines 9+13)		2,194,068,776	493,658,418	607,610,599	3,295,337,793		
15	Construction Work in Progress (13 mo. Average)	II(A)(1)(d)	134,757,788	-	4,772,177	139,529,965	Sheet 3	(a)
16	AFUDC Regulatory Liability (13 mo. Average)	II(A)(1)(i)	54,157,503	-	9,213,804	63,371,307	Sheet 3	(a)
17	Total Investment Base Including CWIP (Lines 14+15-16)		2,274,669,061	493,658,418	603,168,972	3,371,496,451		
	II. REVENUE REQUIREMENTS							
18	Investment Return and Income Taxes - at 10.57% ROE	II(A)	263,101,757	56,577,698	67,261,278	386,940,733	Sheet 4a, Sheet 5a , Sheet 6a	(b)
19	Investment Return and Income Taxes - CWIP - at 10.57% ROE	II(A)	9,665,183	-	(491,679)	9,173,504	Sheet 4a, Sheet 5a , Sheet 6a	(b)
20	Depreciation Expense	II(B)	72,297,134	15,519,668	16,577,959	104,394,761	Sheet 7	(a)
21	Amortization of Loss on Reacquired Debt	II(C)	593,685	246,881	49,668	890,234	Sheet 7	(a)
22	Investment Tax Credit	II(D)	(428,304)	(4,852)	(35,604)	(468,760)	Sheet 7	(a)
23	Property Tax Expense	II(E)	45,144,822	18,087,310	18,717,332	81,949,464	Sheet 7	(a)
24	Payroll Tax Expense	II(F)	322,527	(4,083)	18,291	336,735	Sheet 7	(a)
25	Operation & Maintenance Expense	II(G)	37,849,988	10,282,288	6,368,294	54,500,570	Sheet 7	(a)
26	Administrative & General Expense	II(H)	37,202,294	10,348,117	8,041,502	55,591,913	Sheet 7	(b)
27	Transmission Support Expenses	II(I)	1,625,568	898,916	457,017	2,981,501	Sheet 8	(a)
28	Transmission Related Taxes and Fees Charge	II(J)	9,854,673	158,113	20,627	10,033,413	Note 1	(a)
29	Total Revenue Requirements (Line 18 thru 28)		477,229,327	112,110,056	116,984,685	706,324,068		(b)

Note 1 - Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment B.

Notes

(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
Provided this support because these balances will be revised under the changed rates.
(c) Carrying Charge Factor ([Line 29 - Line 19] / Line 1) 15.70% 17 29% 14.16%

CL&P, PSNH, and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Comparison Under Present Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For Costs in 2014
Sheet 3

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				FF1		FF1		FF1	
Line	Description	FF1 Reference	CL&P	Line	PSNH	Line	WMECO	Line	Notes
	Transmission Plant								
1	Transmission Plant		2,977,602,438	Sheet 9	648,561,975	Sheet 11	829,609,658	Sheet 13	(a)
2	CL&P Dispatch Center	Note 1	32,712		-		-		(a)
3	Net Transmission Plant (line 1-2)		2,977,569,726		648,561,975		829,609,658		
	General Plant								
4	General Plant	FF1 page 204 footnote	102,812,641	Line 99	58,369,540	Line 99	18,348,753	Line 99	(a)
5	CL&P General Dispatch Center	Note 1	15,870,872		-		-		(a)
6	Net General Plant (line 4-5)		86,941,769		58,369,540		18,348,753		
7	Transmission Plant Held for Future Use		35,612,990	Sheet 9	13,626,119	Sheet 11	750,000	Sheet 13	
	Transmission Accumulated Depreciation								
8	Transmission Accum. Depreciation	FF1 page 219	579,929,318	Line 25	117,852,509	Line 25	47,948,646	Line 25	(a)
9	CL&P Dispatch Center Accum. Depreciation	Note 1	(1,482,625)		-		-		(a)
10	Transmission Related General Plant Accum.Depreciation	FF1 page 219	26,085,325	Line 28	14,660,211	Line 28	3,971,742	Line 28	(a)
11	CL&P Dispatch Center General Accum. Depreciation	Note 1	3,717,252		-		-		(a)
12	Net Accumulated Depreciation (line 8-9 10-11)		603,780,016		132,512,720		51,920,388		
	Transmission Accumulated Deferred Taxes								
13	Accumulated Deferred Taxes (281 to 283)	FF1 page 274 & 276 footnote	451,817,902	Line 9 & Line 19	134,008,391	Line 9 & Line 19	213,650,889	Line 9 & Line 19	(a)
14	Accumulated Deferred Taxes (190)	FF1 page 234 footnote	59,128,935	Line 18	10,892,336	Line 18	12,549,258	Line 18	(a)
15	Reserve for Disputed Transactions	FF1 page 234 footnote	2,134,971	Line 18	-	Line 18	-	Line 18	(a)
16	CL&P Dispatch Center ADIT ("T" and General)	Note 1	3,585,862		-		-		(a)
17	Total (line 13-14 15-16)		391,238,076		123,116,055		201,101,631		
18	Unam. Loss on Reacquired Debt (189)	FF1 page 110 footnote	5,711,371	Line 81	2,107,937	Line 81	355,953	Line 81	(a)
	Other Regulatory Assets								
19	FAS 106 (FASB ASC 960/962)	FF1 page 232, 232.1, 232.1 footnote	(9,267)	Line 27	282,181	Line 15	3,119	Line 1	(a)
20	FAS 109 (FASB ASC 740)	FF1 page 232, 232.1, 232.1 footnote	22,783,548	Line 7	8,112,367	Line 1	6,178,066	Line 9	(a)
21	Other Regulatory Liabilities	FF1 page 278 footnote	4,238,164	Line 3	9,419	Line 1	75,473	Line 5	(a)
22	Total (line 19 20-21)		18,536,117		8,385,129		6,105,712		
23	Transmission Prepayments (165)	FF1 page 110 Footnote	19,487,085	Line 57	4,911,873	Line 57	642,737	Line 57	(a)
24	Transmission Materials and Supplies	FF1 page 227 Footnote	36,123,136	Line 8	10,822,161	Line 8	3,067,304	Line 8	(a)
	Cash Working Capital								
25	Operation & Maintenance Expense	Sheet 7	37,849,988		10,282,288		6,368,294		(a)
26	Administrative & General Expense	Sheet 7	37,202,294		10,348,117		8,041,502		(b)
27	Subtotal (line 25 26)		75,052,282		20,630,405		14,409,796		(a)
28	x 45 days/360 days	Section II.A.1(I) of Attachment NU-H	0.125		0.125		0.125		(a)
29	Total current Year End (line 27*28)		9,381,535		2,578,801		1,801,225		(a)
30	Prior Year End Cash Working Capital	Note 1	8,827,812		2,426,116		1,703,777		(a)
31	Average Cash Working Capital [(line 29 30)/2]		9,104,674		2,502,459		1,752,501		(a)
32	Construction Work in Progress (13 mo. avg.)	**Attachment A1**	134,757,788		-		4,772,177		(a)
33	AFUDC Regulatory Liability (13 mo. avg.)	**Attachment A1**	54,157,503		-		9,213,804		(a)

Note 1 - Reflects actual information per Eversource's accounting records.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
Provided this support because these balances will be revised under the changed rates.

The Connecticut Light & Power Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Under Present Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For Costs in 2014
Sheet 4a

	(A)		(B) YEAR END CAPITALIZATION		(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL		(E) = (C) x (D) WEIGHTED COST OF CAPITAL	(F) = (E) Equity Only EQUITY PORTION	(G)
1	LONG-TERM DEBT	$	2,579,060,322	Note 2	45.78%	5.36%	Note 2	2.45%		
2	PREFERRED STOCK	$	116,868,097	Note 2	2.07%	4.80%	Note 2	0.10%	0.10%	
3	COMMON EQUITY	$	2,938,441,767	Note 2	52.15%	10.57%	Note 1	5.51%	5.51%	
4	TOTAL	$	5,634,370,186		100.00%			8.06%	5.61%	

Cost of Capital Rate=

5	(a) Weighted Cost of Capital	=	8.06%										
	(b) Federal Income Tax	= ((	R.O.E.	+ (	Total Inv. (Tax Credit)	+	Eq. AFUDC of Deprec. Exp.	) /	Total Inv. Base	) *	Federal Income Tax Rate	)	
				(	1	-	Federal Income Tax Rate	)					
	Source		Line 4, Col. (F)		Sheet 7		FF1 page 336 ln. 7b + 10b footnotes		For Costs in 2014		Federal Corporate Tax Rate		
6		= ((	5.61%	+ (	(428,304)	+	2,307,409	) /	2,274,669,061	) *	35.00%	)	
7				(	1	-	35.00%	)					
							Federal Corporate Tax Rate						
8		=	3.0653%										
	(c) State Income Tax	= ((	R.O.E.	+ (	Total Inv. (Tax Credit)	+	Eq. AFUDC of Deprec. Exp.	) /	Total Inv. Base	) +	Federal Income Tax	) * (	State Income Tax Rate)
				(	1	-	State Income Tax Rate	)					
	Source		Line 4, Col. (F)		Sheet 7		FF1 page 336 ln. 7b + 10b footnotes		For Costs in 2014		Line 8, Col. (B)		Connecticut Corporate Tax Rate
9		= ((	5.61%	+ (	(428,304)	+	2,307,409	) /	2,274,669,061	) +	3.0653%	) * (	9.00%)
10				(	1	-	9.00%	)					
							Connecticut Corporate Tax Rate						
11		=	0.8662%										
12	(a)+(b)+(c) Cost of Capital Rate	=	11.9915%										

		Total Transmission	-	CWIP	=	Total T - Excluding CWIP	Reference
13	INVESTMENT BASE	$2,274,669,061		$80,600,285		$2,194,068,776	For Costs in 2014
14	x Cost of Capital Rate	11.9915%		11.9915%		11.9915%	Line 12
15	= Investment Return and Income Taxes	$272,766,940		$9,665,183		$263,101,757	

Note 1 - ROE per FERC Order in Docket No. ER04-157 dated March 24, 2008.
Note 2 - Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes

(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) The balance in "Total Inv. Base" will be revised under the Changed Rates

Public Service Company of New Hampshire
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Under Present Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For Costs in 2014
Sheet 5a

	(A)	(B) YEAR END CAPITALIZATION		(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL		(E) = (C) x (D) WEIGHTED COST OF CAPITAL	(F) = (E) Equity Only EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 1,070,020,120	Note 2	46.56%	4.15%	Note 2	1.93%		
2	PREFERRED STOCK	$ -	Note 2	0.00%	0.00%	Note 2	0.00%	0.00%	
3	COMMON EQUITY	$ 1,228,095,985	Note 2	53.44%	10.57%	Note 1	5.65%	5.65%	
4	TOTAL	$ 2,298,116,105		100.00%			7.58%	5.65%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 7.58%

(b) Federal Income Tax = ((R.O.E. + (Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate)) / Total Inv. Base) * Federal Income Tax Rate)

	Source			Sheet 7		FF1 page 336 ln. 7b + 10b footnotes		For Costs in 2014		Federal Corporate Tax Rate
6		= ((	5.65%	+ ((4,852)	+	230,083	) /	493,658,418	) *	35.00%)
7				(1	-	35.00% Federal Corporate Tax Rate	)			
8		=	3.0669%							

(c) State Income Tax = ((R.O.E. + (Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate)) / Total Inv. Base) + Federal Income Tax) * (State Income Tax Rate)

	Source			Sheet 7		FF1 page 336 ln. 7b + 10b footnotes		For Costs in 2014				New Hampshire Corporate Tax Rate
9		= ((	5.65%	+ ((4,852)	+	230,083	) /	493,658,418	) +	3.0669%	) * (	8.50%)
10				(1	-	8.50% New Hampshire Corporate Tax Rate	)					
11		=	0.8140%									
12	(a)+(b)+(c) Cost of Capital Rate	=	11.4609%									

		Total Transmission	-	CWIP	=	Total T - Excluding CWIP	Reference
13	INVESTMENT BASE	$493,658,418		-		$493,658,418	For Costs in 2014
14	x Cost of Capital Rate	11.4609%		11.4609%		11.4609%	Line 12
15	= Investment Return and Income Taxes	$56,577,698		-		$56,577,698	

Note 1 - ROE per FERC Order in Docket No. ER04-157 dated March 24, 2008.
Note 2 - Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) The balance in "Total Inv. Base" will be revised under the Changed Rates

Western Massachusetts Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Under Present Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For Costs in 2014
Sheet 6a

	(A)	(B) YEAR END CAPITALIZATION		(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL		(E) = (C) x (D) WEIGHTED COST OF CAPITAL	(F) = (E) Equity Only EQUITY PORTION	(G)
1	LONG-TERM DEBT	$ 567,833,428	Note 2	49.55%	4.31%	Note 2	2.14%		
2	PREFERRED STOCK	$ -	Note 2	0.00%	0.00%	Note 2	0.00%	0.00%	
3	COMMON EQUITY	$ 578,162,814	Note 2	50.45%	10.57%	Note 1	5.33%	5.33%	
4	TOTAL	$ 1,145,996,242		100.00%			7.47%	5.33%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 7.47%

(b) Federal Income Tax = ((R.O.E. + (Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate) / Total Inv. Base) * Federal Income Tax Rate)

	Source				Sheet 7		FF1 page 336 ln. 7b + 10b footnotes		For Costs in 2014		Federal Corporate Tax Rate	
6		= ((	5.33%	+ (	(35,604)	+	186,099	) /	603,168,972	) *	35.00%	)
7				(	1	-	35.00%	)				
							Federal Corporate Tax Rate					
8		=	2.8834%									

(c) State Income Tax = ((R.O.E. + (Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate) / Total Inv. Base) + Federal Income Tax) * (State Income Tax Rate)

	Source				Sheet 7		FF1 page 336 ln. 7b + 10b footnotes		For Costs in 2014				Massachusetts Corporate Tax Rate	
9		= ((	5.33%	+ (	(35,604)	+	186,099	) /	603,168,972	) +	2.8834%	) * (	8.00%	)
10				(	1	-	8.00%	)						
							Massachusetts Corporate Tax Rate							
11		=	0.7164%											

12 (a)+(b)+(c) Cost of Capital Rate = 11.0698%

		Total Transmission	-	CWIP	=	Total T - Excluding CWIP	Reference
13	INVESTMENT BASE	$603,168,972		($4,441,627)		$607,610,599	For Costs in 2014
14	x Cost of Capital Rate	11.0698%		11.0698%		11.0698%	Line 12
15	= Investment Return and Income Taxes	$66,769,599		($491,679)		$67,261,278	

Note 1 - ROE per FERC Order in Docket No. ER04-157 dated March 24, 2008.
Note 2 - Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) The balance in "Total Inv. Base" will be revised under the Changed Rates

CL&P, PSNH, and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Comparison Under Present Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For Costs in 2014
Sheet 7

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line	Description	FF1 Reference	CL&P Year End	FF1 Line	PSNH Year End	FF1 Line	WMECO Year End	FF1 Line	Notes
	Depreciation Expense								
1	Transmission Depreciation	FF1 page 336	69,626,166	7b	12,792,512	7b	15,972,687	7b	(a)
2	General Depreciation	FF1 page 336 footnote	4,980,574	10b	2,727,156	10b	789,658	10b	(a)
3	AFUDC Regulatory Credit	Attachment A1	1,145,364		-		184,386		(a)
4	Dispatch Plant Depreciation ("T" and General)	Note 1	1,164,242		-		-		(a)
5	Net Depreciation Expense (line 1+2-3-4)		72,297,134		15,519,668		16,577,959		
6	Amortization of Loss on Reacquired Debt	FF1 page 114 footnote	593,685	64c	246,881	64c	49,668	64c	(a)
	Investment Tax Credits								
7	Amortization of Investment Tax Credits	FF1 page 266 footnote	(428,304)	8f	(4,852)	8f	(35,604)	8f	(a)
8	Dispatch Center ITC ("T" and General)	Note 1	-		-		-		(a)
9	Net Investment Tax Credit (line 7-8)		(428,304)		(4,852)		(35,604)		
	Property Taxes								
10	Transmission Property Taxes	FF1 page 262 footnote	45,370,701	25i	18,087,310	Note 3	18,717,332	32i	(a)
11	General Property Taxes (included in line 10)	Note 2	-		-		-		(a)
12	Dispatch Center Property Taxes ("T" and General)	Note 1	225,879		-		-		(a)
13	Net Property Taxes (line 10+11-12)		45,144,822		18,087,310		18,717,332		
	Payroll Taxes:								
14	Federal Unemployment	FF1 page 262 footnote	5,226	3i	(51)	2i	283	3i	(a)
15	FICA	FF1 page 262 footnote	233,351	5i	(3,062)	4i	13,202	5i	(a)
16	Medicare	FF1 page 262 footnote	65,613	9i	(816)	7i	3,757	9i	(a)
17	CT Unemployment	FF1 page 262, 262.1, 262 footnote	16,786	15i	(128)	7i	852	13i	(a)
18	DC Unemployment	FF1 page 262.1 footnote	11	14i	-		1	6i	(a)
19	FL Unemployment	FF1 page 262.1 footnote	1	18i	-	27i	-	10i	(a)
20	MI Unemployment	FF1 page 262.1 footnote	6	22i	-	31i	-	14i	(a)
21	MA Unemployment	FF1 page 262, 262.1, 262 footnote	(285)	32i	2	15i	69	22i	(a)
22	MA Universal Health	FF1 page 262, 262.1, 262 footnote	64	33i	(1)	16i	19	27i	(a)
23	NH Unemployment	FF1 page 262.1, 262, 262 footnote	1,754	4i	(27)	14i	108	37i	(a)
24	NJ Unemployment	FF1 page 262 footnote	-		-		-		(a)
25	NY Unemployment	FF1 page 262.1 footnote	-	10i	-		-		(a)
26	Total Payroll Tax Exp (sum of line 14 through 25)		322,527		(4,083)		18,291		
	Transmission Operation and Maintenance								
27	Operation and Maintenance	FF1 page 321	77,432,007	112	51,082,852	112	20,725,279	112	(a)
28	Transmission of Electricity by Others - #565	FF1 page 321	21,727,966	96	37,174,569	96	13,174,678	96	(a)
29		FF1 page 321		84		84		84	(a)
30	Account 561.1	FF1 page 321	3,245,594	85	653,575	85	12,368	85	(a)
31	Account 561 2	FF1 page 321	5,212,556	86	474,690	86	50,569	86	(a)
32	Account 561 3	FF1 page 321	2,238,612	87	36,962	87	13,262	87	(a)
33	Account 561.4	FF1 page 321	7,157,291	88	2,460,768	88	1,106,108	88	(a)
34	Station Expenses & Rents - #562 / #567	FF1 page 321	-	93+98	-	93+98	-	93+98	(a)
35	Net O&M (line 27 - [sum lines 28 through 34])		37,849,988		10,282,288		6,368,294		
	Transmission Administrative and General								
36	Administrative and General	FF1 page 320 footnote	37,202,294	197	10,348,117	197	8,041,502	197	(a)
37	Public Education Expenses	FF1 page 114 footnote	-	49	-	49	-	49	(a)
38	Total Administrative and General (line 36+37)		37,202,294		10,348,117		8,041,502		(b)

Note 1 - Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.
Note 2 - Reflects actual information per Eversource's accounting records.
Note 3 -This includes local New Hampshire, Vermont, and Maine property taxes (Page 262 ln, 23i, footnote + Page 262 ln, 30i, footnote + Page 262.1 ln, 2i, footnote).

Notes

(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
Provided this support because these balances will be revised under the changed rates.

Exhibit No. ES-224
Schedule 3

Category A Revenue Requirements under the Changed Rates for 2016

Eversource Energy Service Company

CL&P, PSNH, and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Under Changed Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For the Calendar year 2016

	(A)	(B)	(C)	(D)	(E)	(F)=(C)+(D)+(E)
Line	**Description**	**Reference**	**CL&P**	**PSNH**	**WMECO**	**Total NU**
1	2014 Actual Schedule 21-ES, Category A Revenue Requirement		$ 485,287,209 (1)	$ 113,771,603 (2)	$ 119,156,448 (3)	$ 718,215,260
2	Estimated 2015 Schedule 21-ES, Category A Plant Additions	(4)	$ 278,000,000	$ 123,000,000	$ 100,000,000	$ 501,000,000
3	Carrying Charge Factor (CCF)	Exhibit No. ES-224, Schedule 2, Page 2 of 7, Note (c)	15.70%	17.29%	14.16%	15.78%
4	2015 Incremental Estimated Schedule 21-ES, Category A Revenue Requirement	Line 2 x 3	43,646,000	21,266,700	14,160,000	79,072,700
5	2015 Incremental Estimated Schedule 21-ES, Category A CWIP Revenue Requirements	(4)	$ 6,218,000	$ -	$ (999,000)	$ 5,219,000
6	Total Estimated Schedule 21-ES, Category A Revenue Requirement for 2015	Line 1 + 4 + 5	$ 535,151,209	$ 135,038,303	$ 132,317,448	$ 802,506,960
7	Estimated 2016 Schedule 21-ES, Category A Plant Additions	(4)	$ 72,000,000	$ 117,000,000	$ 92,000,000	$ 281,000,000
8	Carrying Charge Factor (CCF)	Line 3	15.70%	17.29%	14.16%	15.86%
9	2016 Incremental Estimated Schedule 21-ES, Category A Revenue Requirement	Line 7 x 8	11,304,000	20,229,300	13,027,200	44,560,500
10	Total Estimated Schedule 21-ES, Category A Revenue Requirement for 2016	Line 6 + 9	$ 546,455,209	$ 155,267,603	$ 145,344,648	$ 847,067,460

Notes:
(1) Exhibit ES-224, Schedule 3, Page 2 of 7, Line 29(C)
(2) Exhibit ES-224, Schedule 3, Page 2 of 7, Line 29(D)
(3) Exhibit ES-224, Schedule 3, Page 2 of 7, Line 29(E)
(4) Based on Eversource's Forecast

CL&P, PSNH, and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Under Changed Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For Costs in 2014
Sheet 2a

Line	(A)	(B) Attachment H Reference Section:	(C) CL&P	(D) PSNH	(E) WMECO	(F) Total	(G) Source	Notes
	I. INVESTMENT BASE							
1	Transmission Plant	II(A)(1)(a)	2,977,569,726	648,561,975	829,609,658	4,455,741,359	Sheet 3	(a)
2	General Plant	II(A)(1)(b)	86,941,769	58,369,540	18,348,753	163,660,062	Sheet 3	(a)
3	Plant Held For Future Use	II(A)(1)(c)	35,612,990	13,626,119	750,000	49,989,109	Sheet 3	(a)
4	Total Plant (Lines 1+2+3)		3,100,124,485	720,557,634	848,708,411	4,669,390,530		
5	Accumulated Depreciation	II(A)(1)(e)	603,780,016	132,512,720	51,920,388	788,213,124	Sheet 3	(a)
6	Accumulated Deferred Income Taxes	II(A)(1)(f)	391,238,076	123,116,055	201,101,631	715,455,762	Sheet 3	(a)
7	Loss On Reacquired Debt	II(A)(1)(g)	5,711,371	2,107,937	355,953	8,175,261	Sheet 3	(a)
8	Other Regulatory Assets	II(A)(1)(h)	25,689,443	9,866,751	8,048,921	43,605,115	Sheet 3	(b)
9	Net Investment (Line 4-5-6+7+8)		2,136,507,207	476,903,547	604,091,266	3,217,502,020		(b)
10	Prepayments	II(A)(1)(j)	19,487,085	4,911,873	642,737	25,041,695	Sheet 3	(a)
11	Materials & Supplies	II(A)(1)(k)	36,123,136	10,822,161	3,067,304	50,012,601	Sheet 3	(a)
12	Cash Working Capital	II(A)(1)(l)	9,551,757	2,595,060	1,873,952	14,020,769	Sheet 3	(b)
13	Sub Total (Line 10+11+12)		65,161,978	18,329,094	5,583,993	89,075,065		
14	Total Investment Base Excluding CWIP (Lines 9+13)		2,201,669,185	495,232,641	609,675,259	3,306,577,085		(b)
15	Construction Work in Progress (13 mo. Average)	II(A)(1)(d)	134,757,788	-	4,772,177	139,529,965	Sheet 3	(a)
16	AFUDC Regulatory Liability (13 mo. Average)	II(A)(1)(i)	54,157,503	-	9,213,804	63,371,307	Sheet 3	(a)
17	Total Investment Base Including CWIP (Lines 14+15-16)		2,282,269,470	495,232,641	605,233,632	3,382,735,743		(b)
	II. REVENUE REQUIREMENTS							
18	Investment Return and Income Taxes - at 10.57% ROE	II(A)	264,006,555	56,757,623	67,489,832	388,254,010	Sheet 4a, Sheet 5a , Sheet 6a	(b)
19	Investment Return and Income Taxes - CWIP - at 10.57% ROE	II(A)	9,664,941	-	(491,679)	9,173,262	Sheet 4a, Sheet 5a , Sheet 6a	(b)
20	Depreciation Expense	II(B)	72,297,134	15,519,668	16,577,959	104,394,761	Sheet 7	(a)
21	Amortization of Loss on Reacquired Debt	II(C)	593,685	246,881	49,668	890,234	Sheet 7	(a)
22	Investment Tax Credit	II(D)	(428,304)	(4,852)	(35,604)	(468,760)	Sheet 7	(a)
23	Property Tax Expense	II(E)	45,144,822	18,087,310	18,717,332	81,949,464	Sheet 7	(a)
24	Payroll Tax Expense	II(F)	322,527	(4,083)	18,291	336,735	Sheet 7	(a)
25	Operation & Maintenance Expense	II(G)	37,849,988	10,282,288	6,368,294	54,500,570	Sheet 7	(a)
26	Administrative & General Expense	II(H)	44,355,620	11,829,739	9,984,711	66,170,070	Sheet 7	(b)
27	Transmission Support Expenses	II(I)	1,625,568	898,916	457,017	2,981,501	Sheet 8	(a)
28	Transmission Related Taxes and Fees Charge	II(J)	9,854,673	158,113	20,627	10,033,413	Note 1	(a)
29	Total Revenue Requirements (Line 18 thru 28)		485,287,209	113,771,603	119,156,448	718,215,260		(b)

Note 1 - Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment B.

Notes

(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247

(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

CL&P, PSNH, and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Under Changed Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For Costs in 2014
Sheet 3

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	
				FF1		FF1		FF1	
Line	Description	FF1 Reference	CL&P	Line	PSNH	Line	WMECO	Line	Notes
	Transmission Plant								
1	Transmission Plant		2,977,602,438	Sheet 9	648,561,975	Sheet 11	829,609,658	Sheet 13	(a)
2	CL&P Dispatch Center	Note 1	32,712		-		-		(a)
3	Net Transmission Plant (lne 1-2)		2,977,569,726		648,561,975		829,609,658		
	General Plant								
4	General Plant	FF1 page 204 footnote	102,812,641	Line 99	58,369,540	Line 99	18,348,753	Line 99	(a)
5	CL&P General Dispatch Center	Note 1	15,870,872		-		-		(a)
6	Net General Plant (line 4-5)		86,941,769		58,369,540		18,348,753		
7	Transmission Plant Held for Future Use		35,612,990	Sheet 9	13,626,119	Sheet 11	750,000	Sheet 13	
	Transmission Accumulated Depreciation								
8	Transmission Accum. Depreciation	FF1 page 219	579,929,318	Line 25	117,852,509	Line 25	47,948,646	Line 25	(a)
9	CL&P Dispatch Center Accum. Depreciation	Note 1	(1,482,625)		-		-		(a)
10	Transmission Related General Plant Accum.Depreciation	FF1 page 219	26,085,325	Line 28	14,660,211	Line 28	3,971,742	Line 28	(a)
11	CL&P Dispatch Center General Accum. Depreciation	Note 1	3,717,252		-		-		(a)
12	Net Accumulated Depreciation (line 8-9+10-11)		603,780,016		132,512,720		51,920,388		
	Transmission Accumulated Deferred Taxes								
13	Accumulated Deferred Taxes (281 to 283)	FF1 page 274 & 276 footnote	451,817,902	Line 9 & Line 19	134,008,391	Line 9 & Line 19	213,650,889	Line 9 & Line 19	(a)
14	Accumulated Deferred Taxes (190)	FF1 page 234 footnote	59,128,935	Line 18	10,892,336	Line 18	12,549,258	Line 18	(a)
15	Reserve for Disputed Transactions	FF1 page 234 footnote	2,134,971	Line 18	-	Line 18	-	Line 18	(a)
16	CL&P Dispatch Center ADIT ("T" and General)	Note 1	3,585,862		-		-		(a)
17	Total (line 13-14+15-16)		391,238,076		123,116,055		201,101,631		
18	Unam. Loss on Reacquired Debt (189)	FF1 page 110 footnote	5,711,371	Line 81	2,107,937	Line 81	355,953	Line 81	(a)
	Other Regulatory Assets								
19	Unamortized Balance of Transmission Merger-Related Costs	Exhibit No. ES-220	7,153,326	Page 1 of 8, Line 4(B)	1,481,622	Page 3 of 8, Line 4(B)	1,943,209	Page 4 of 8, Line 4(B)	(b)
20	FAS 106 (FASB ASC 960/962)	FF1 page 232, 232.1, 232.1 footnote	(9,267)	Line 27	282,181	Line 15	3,119	Line 1	(a)
21	FAS 109 (FASB ASC 740)	FF1 page 232, 232.1, 232.1 footnote	22,783,548	Line 7	8,112,367	Line 1	6,178,066	Line 9	(a)
22	Other Regulatory Liabilities	FF1 page 278 footnote	4,238,164	Line 3	9,419	Line 1	75,473	Line 5	(a)
23	Total (line 19+20-21)		25,689,443		9,866,751		8,048,921		
24	Transmission Prepayments (165)	FF1 page 110 Footnote	19,487,085	Line 57	4,911,873	Line 57	642,737	Line 57	(a)
25	Transmission Materials and Supplies	FF1 page 227 Footnote	36,123,136	Line 8	10,822,161	Line 8	3,067,304	Line 8	(a)
	Cash Working Capital								
26	Operation & Maintenance Expense	Sheet 7	37,849,988		10,282,288		6,368,294		(a)
27	Administrative & General Expense	Sheet 7	44,355,620		11,829,739		9,984,711		(c)
28	Subtotal (line 25+26)		82,205,608		22,112,027		16,353,005		(c)
29	x 45 days/360 days	Section II.A.1(I) of Attachment NU-H	0.125		0.125		0.125		(a)
30	Total current Year End (line 27*28)		10,275,701		2,764,003		2,044,126		(c)
31	Prior Year End Cash Working Capital	Note 1	8,827,812		2,426,116		1,703,777		(a)
32	Average Cash Working Capital [(line 29+30)/2]		9,551,757		2,595,060		1,873,952		(c)
33	Construction Work in Progress (13 mo. avg.)	**Attachment A1**	134,757,788		-		4,772,177		(a)
34	AFUDC Regulatory Liability (13 mo. avg.)	**Attachment A1**	54,157,503		-		9,213,804		(a)

Note 1 - Reflects actual information per Eversource's accounting records.

Notes:

(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset
(c) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light & Power Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Under Changed Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For Costs in 2014
Sheet 4a

	(A)	(B) YEAR END CAPITALIZATION		(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL		(E) = (C) x (D) WEIGHTED COST OF CAPITAL	(F) = (E) Equity Only EQUITY PORTION
1	LONG-TERM DEBT	$ 2,579,060,322	Note 2	45.78%	5.36%	Note 2	2.45%	
2	PREFERRED STOCK	$ 116,868,097	Note 2	2.07%	4.80%	Note 2	0.10%	0.10%
3	COMMON EQUITY	$ 2,938,441,767	Note 2	52.15%	10.57%	Note 1	5.51%	5.51%
4	TOTAL	$ 5,634,370,186		100.00%			8.06%	5.61%

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 8.06%

	(b) Federal Income Tax	= ((	R.O.E.	+ (	Total Inv. (Tax Credit)	+	Eq. AFUDC of Deprec. Exp.	) /	Total Inv. Base (a)	) *	Federal Income Tax Rate	)	
				(	1	-	Federal Income Tax Rate	)					
	Source		Line 4, Col. (F)		Sheet 7		FF1 page 336 ln. 7b + 10b footnotes		For Costs in 2014		Federal Corporate Tax Rate		
6		= ((	5.61%	+ (	(428,304)	+	2,307,409	) /	2,282,269,470	) *	35.00%	)	
7				(	1	-	35.00% Federal Corporate Tax Rate	)					
8		=	3.0651%										
	(c) State Income Tax	= ((	R.O.E.	+ (	Total Inv. (Tax Credit)	+	Eq. AFUDC of Deprec. Exp.	) /	Total Inv. Base	) +	Federal Income Tax	) * (	State Income Tax Rate)
				(	1	-	State Income Tax Rate	)					
	Source		Line 4, Col. (F)		Sheet 7		FF1 page 336 ln. 7b + 10b footnotes		For Costs in 2014		Line 8, Col. (B)		Connecticut Corporate Tax Rate
9		= ((	5.61%	+ (	(428,304)	+	2,307,409	) /	2,282,269,470	) +	3.0651%	) * (	9.00%)
10				(	1	-	9.00% Connecticut Corporate Tax Rate	)					
11		=	0.8661%										
12	(a)+(b)+(c) Cost of Capital Rate	=	11.9912%										

		Total Transmission	-	CWIP	=	Total T - Excluding CWIP	Reference
13	INVESTMENT BASE	$2,282,269,470		$80,600,285		$2,201,669,185	For Costs in 2014
14	x Cost of Capital Rate	11.9912%		11.9912%		11.9912%	Line 12
15	= Investment Return and Income Taxes	$273,671,497		$9,664,941		$264,006,555	

Note 1 - ROE per FERC Order in Docket No. ER04-157 dated March 24, 2008.
Note 2 - Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes

(a) Proposed revisions to "Total Inv. Base" reflects the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the addition of the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

Source of all other information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247

Public Service Company of New Hampshire
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Under Changed Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For Costs in 2014
Sheet 5a

	(A)	(B) YEAR END CAPITALIZATION		(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL		(E) = (C) x (D) WEIGHTED COST OF CAPITAL	(F) = (E) Equity Only EQUITY PORTION
1	LONG-TERM DEBT	$ 1,070,020,120	Note 2	46.56%	4.15%	Note 2	1.93%	
2	PREFERRED STOCK	$ -	Note 2	0.00%	0.00%	Note 2	0.00%	0.00%
3	COMMON EQUITY	$ 1,228,095,985	Note 2	53.44%	10.57%	Note 1	5.65%	5.65%
4	TOTAL	$ 2,298,116,105		100.00%			7.58%	5.65%

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 7.58%

(b) Federal Income Tax = ((R.O.E. + (Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate)) / Total Inv. Base) * Federal Income Tax Rate)

				Sheet 7		FF1 page 336 ln. 7b + 10b footnotes		For Costs in 2014		Federal Corporate Tax Rate	
6	Source	= ((	5.65%	+ ((4,852)	+	230,083	) /	495,232,641	) *	35.00%	)
7				(1	-	35.00% Federal Corporate Tax Rate	)				
8		=	3.0668%								

(c) State Income Tax = ((R.O.E. + (Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate)) / Total Inv. Base) + Federal Income Tax) * (State Income Tax Rate)

				Sheet 7		FF1 page 336 ln. 7b + 10b footnotes		For Costs in 2014				New Hampshire Corporate Tax Rate	
9	Source	= ((	5.65%	+ ((4,852)	+	230,083	) /	495,232,641	) +	3.0668%	) * (	8.50%	)
10				(1	-	8.50% New Hampshire Corporate Tax Rate	)						
11		=	0.8140%										

12 (a)+(b)+(c) Cost of Capital Rate = 11.4608%

		Total Transmission	-	CWIP	=	Total T - Excluding CWIP	Reference
13	INVESTMENT BASE	$495,232,641		-		$495,232,641	For Costs in 2014
14	x Cost of Capital Rate	11.4608%		11.4608%		11.4608%	Line 12
15	= Investment Return and Income Taxes	$56,757,623		-		$56,757,623	

Note 1 - ROE per FERC Order in Docket No. ER04-157 dated March 24, 2008.
Note 2 - Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes

(a) Proposed revisions to "Total Inv. Base" reflects the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the addition of the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

Source of all other information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247

Western Massachusetts Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Under Changed Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For Costs in 2014
Sheet 6a

	(A)	(B) YEAR END CAPITALIZATION		(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL		(E) = (C) x (D) WEIGHTED COST OF CAPITAL	(F) = (E) Equity Only EQUITY PORTION
1	LONG-TERM DEBT	$ 567,833,428	Note 2	49.55%	4.31%	Note 2	2.14%	
2	PREFERRED STOCK	$ -	Note 2	0.00%	0.00%	Note 2	0.00%	0.00%
3	COMMON EQUITY	$ 578,162,814	Note 2	50.45%	10.57%	Note 1	5.33%	5.33%
4	TOTAL	$ 1,145,996,242		100.00%			7.47%	5.33%

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 7.47%

(b) Federal Income Tax = ((R.O.E. + (Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / Total Inv. Base) * Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

Source: Sheet 7; FF1 page 336 ln. 7b + 10b footnotes; For Costs in 2014; Federal Corporate Tax Rate

6 = ((5.33% + ((35,604) + 186,099) / 605,233,632) * 35.00%)
7 (1 - 35.00%) Federal Corporate Tax Rate

8 = 2.8834%

(c) State Income Tax = ((R.O.E. + (Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / Total Inv. Base) + Federal Income Tax) * (State Income Tax Rate) / (1 - State Income Tax Rate)

Source: Sheet 7; FF1 page 336 ln. 7b + 10b footnotes; For Costs in 2014; Massachusetts Corporate Tax Rate

9 = ((5.33% + ((35,604) + 186,099) / 605,233,632) + 2.8834%) * (8.00%)
10 (1 - 8.00%) Massachusetts Corporate Tax Rate

11 = 0.7164%

12 (a)+(b)+(c) Cost of Capital Rate = 11.0698%

		Total Transmission	- CWIP	= Total T - Excluding CWIP	Reference
13	INVESTMENT BASE	$605,233,632	($4,441,627)	$609,675,259	For Costs in 2014
14	x Cost of Capital Rate	11.0698%	11.0698%	11.0698%	Line 12
15	= Investment Return and Income Taxes	$66,998,153	($491,679)	$67,489,832	

Note 1 - ROE per FERC Order in Docket No. ER04-157 dated March 24, 2008.
Note 2 - Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes

(a) Proposed revisions to "Total Inv. Base" reflects the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the addition of the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

Source of all other information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247

CL&P, PSNH, and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Under Changed Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For Costs in 2014
Sheet 7

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	
Line	Description	FF1 Reference	CL&P Year End	FF1 Line	PSNH Year End	FF1 Line	WMECO Year End	FF1 Line	Notes
	Depreciation Expense								
1	Transmission Depreciation	FF1 page 336	69,626,166	7b	12,792,512	7b	15,972,687	7b	(a)
2	General Depreciation	FF1 page 336 footnote	4,980,574	10b	2,727,156	10b	789,658	10b	(a)
3	AFUDC Regulatory Credit	Attachment A1	1,145,364		-		184,386		(a)
4	Dispatch Plant Depreciation ("T" and General)	Note 1	1,164,242		-		-		(a)
5	Net Depreciation Expense (line 1+2-3-4)		72,297,134		15,519,668		16,577,959		
6	Amortization of Loss on Reacquired Debt	FF1 page 114 footnote	593,685	64c	246,881	64c	49,668	64c	(a)
	Investment Tax Credits								
7	Amortization of Investment Tax Credits	FF1 page 266 footnote	(428,304)	8f	(4,852)	8f	(35,604)	8f	(a)
8	Dispatch Center ITC ("T" and General)	Note 1	-		-		-		(a)
9	Net Investment Tax Credit (line 7-8)		(428,304)		(4,852)		(35,604)		
	Property Taxes								
10	Transmission Property Taxes	FF1 page 262 footnote	45,370,701	25i	18,087,310	Note 3	18,717,332	32i	(a)
11	General Property Taxes (included in line 10)	Note 2	-		-		-		(a)
12	Dispatch Center Property Taxes ("T" and General)	Note 1	225,879		-		-		(a)
13	Net Property Taxes (line 10+11-12)		45,144,822		18,087,310		18,717,332		
	Payroll Taxes:								
14	Federal Unemployment	FF1 page 262 footnote	5,226	3i	(51)	2i	283	3i	(a)
15	FICA	FF1 page 262 footnote	233,351	5i	(3,062)	4i	13,202	5i	(a)
16	Medicare	FF1 page 262 footnote	65,613	9i	(816)	7i	3,757	9i	(a)
17	CT Unemployment	FF1 page 262, 262.1, 262 footnote	16,786	15i	(128)	7i	852	13i	(a)
18	DC Unemployment	FF1 page 262.1 footnote	11	14i	-		1	6i	(a)
19	FL Unemployment	FF1 page 262.1 footnote	1	18i	-	27i	-	10i	(a)
20	MI Unemployment	FF1 page 262.1 footnote	6	22i	-	31i	-	14i	(a)
21	MA Unemployment	FF1 page 262, 262.1, 262 footnote	(285)	32i	2	15i	69	22i	(a)
22	MA Universal Health	FF1 page 262, 262.1, 262 footnote	64	33i	(1)	16i	19	27i	(a)
23	NH Unemployment	FF1 page 262.1, 262, 262 footnote	1,754	4i	(27)	14i	108	37i	(a)
24	NJ Unemployment	FF1 page 262 footnote	-		-		-		(a)
25	NY Unemployment	FF1 page 262.1 footnote	-	10i	-		-		(a)
26	Total Payroll Tax Exp (sum of line 14 through 25)		322,527		(4,083)		18,291		
	Transmission Operation and Maintenance								
27	Operation and Maintenance	FF1 page 321	77,432,007	112	51,082,852	112	20,725,279	112	(a)
28	Transmission of Electricity by Others - #565	FF1 page 321	21,727,966	96	37,174,569	96	13,174,678	96	(a)
29		FF1 page 321		84		84		84	(a)
30	Account 561.1	FF1 page 321	3,245,594	85	653,575	85	12,368	85	(a)
31	Account 561.2	FF1 page 321	5,212,556	86	474,690	86	50,569	86	(a)
32	Account 561.3	FF1 page 321	2,238,612	87	36,962	87	13,262	87	(a)
33	Account 561.4	FF1 page 321	7,157,291	88	2,460,768	88	1,106,108	88	(a)
34	Station Expenses & Rents - #562 / #567	FF1 page 321	-	93+98	-	93+98	-	93+98	(a)
35	Net O&M (line 27 - [sum lines 28 through 34])		37,849,988		10,282,288		6,368,294	Line 23 (H)	
	Transmission Administrative and General								
36	Administrative and General	FF1 page 320 footnote	37,202,294	197	10,348,117	197	8,041,502	197	(a)
37	Transmission Merger-Related Costs	Exhibit No. ES-220	7,153,326	Page 1 of 8, Line 2(B)	1,481,622	Page 3 of 8, Line 2(B)	1,943,209	Page 4 of 8, Line 2(B)	(b)
38	Public Education Expenses	FF1 page 114 footnote	-	49	-	49	-	49	(a)
39	Total Administrative and General (line 36+37)		44,355,620		11,829,739		9,984,711		(b)

Note 1 - Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.
Note 2 - Reflects actual information per the Company's accounting records.
Note 3 -This includes local New Hampshire, Vermont, and Maine property taxes (Page 262 ln, 23i, footnote + Page 262 ln, 30i, footnote + Page 262.1 ln, 2i, footnote).

Notes
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Exhibit No. ES-224
Schedule 4

Category A Revenue Requirements under the Changed Rates for 2017

Eversource Energy Service Company

CL&P, PSNH, and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21 ES (Formerly Schedule 21 NU) Revenue Requirement Under Changed Rates
Under Schedule ES H (Formerly Schedule NU H)
For the Calendar year 2017

	(A)	(B)	(C)	(D)	(E)	(F) (C)+(D)+(E)
Line	**Description**	**Reference**	**CL&P**	**PSNH**	**WMECO**	**Total NU**
1	2014 Actual Schedule 21-ES, Category A Revenue Requirement		$ 485,800,618 (1)	$ 113,875,868 (2)	$ 119,282,840 (3)	$ 718,959,326
2	Estimated 2015 Schedule 21-ES, Category A Plant Additions	(4)	$ 278,000,000	$ 123,000,000	$ 100,000,000	$ 501,000,000
3	Carrying Charge Factor (CCF)	Exhibit No. ES-224, Schedule 2, Page 2 of 7, Note (c)	15.70%	17.29%	14.16%	15.78%
4	2015 Incremental Estimated Schedule 21-ES, Category A Revenue Requirement	Line 2 x 3	43,646,000	21,266,700	14,160,000	79,072,700
5	2015 Incremental Estimated Schedule 21-ES, Category A CWIP Revenue Requirements	(4)	$ 6,218,000	$ -	$ (999,000)	$ 5,219,000
6	Total Estimated Schedule 21-ES, Category A Revenue Requirement for 2015	Line 1 + 4 + 5	$ 535,664,618	$ 135,142,568	$ 132,443,840	$ 803,251,026
7	Estimated 2016 Schedule 21-ES, Category A Plant Additions	(4)	$ 72,000,000	$ 117,000,000	$ 92,000,000	$ 281,000,000
8	Carrying Charge Factor (CCF)	Line 3	15.70%	17.29%	14.16%	15.86%
9	2016 Incremental Estimated Schedule 21-ES, Category A Revenue Requirement	Line 7 x 8	11,304,000	20,229,300	13,027,200	44,560,500
10	Total Estimated Schedule 21-ES, Category A Revenue Requirement for 2016	Line 6 + 9	$ 546,968,618	$ 155,371,868	$ 145,471,040	$ 847,811,526 (5)

Notes:
(1) Exhibit ES 224, Schedule 4, Page 2 of 7, Line 29(C)
(2) Exhibit ES 224, Schedule 4, Page 2 of 7, Line 29(D)
(3) Exhibit ES 224, Schedule 4, Page 2 of 7, Line 29(E)
(4) Based on Eversource's Forecast
(5) The revenue requirements calculations for the calendar year 2016 (including any forecast for 2016) are used as an estimate for the revenue requirements for 2017, which are used to calculate the revenue impact of the proposed cost recovery.

CL&P, PSNH, and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Under Changed Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For Costs in 2014
Sheet 2a

Line	(A)	(B) Attachment H Reference Section:	(C) CL&P	(D) PSNH	(E) WMECO	(F) Total	(G) Source	Notes
	I. INVESTMENT BASE							
1	Transmission Plant	II(A)(1)(a)	2,977,569,726	648,561,975	829,609,658	4,455,741,359	Sheet 3	(a)
2	General Plant	II(A)(1)(b)	86,941,769	58,369,540	18,348,753	163,660,062	Sheet 3	(a)
3	Plant Held For Future Use	II(A)(1)(c)	35,612,990	13,626,119	750,000	49,989,109	Sheet 3	(a)
4	Total Plant (Lines 1+2+3)		3,100,124,485	720,557,634	848,708,411	4,669,390,530		
5	Accumulated Depreciation	II(A)(1)(e)	603,780,016	132,512,720	51,920,388	788,213,124	Sheet 3	(a)
6	Accumulated Deferred Income Taxes	II(A)(1)(f)	391,238,076	123,116,055	201,101,631	715,455,762	Sheet 3	(a)
7	Loss On Reacquired Debt	II(A)(1)(g)	5,711,371	2,107,937	355,953	8,175,261	Sheet 3	(a)
8	Other Regulatory Assets	II(A)(1)(h)	29,266,106	10,607,563	9,020,526	48,894,194	Sheet 3	(b)
9	Net Investment (Line 4-5-6+7+8)		2,140,083,870	477,644,359	605,062,871	3,222,791,099		(b)
10	Prepayments	II(A)(1)(j)	19,487,085	4,911,873	642,737	25,041,695	Sheet 3	(a)
11	Materials & Supplies	II(A)(1)(k)	36,123,136	10,822,161	3,067,304	50,012,601	Sheet 3	(a)
12	Cash Working Capital	II(A)(1)(l)	10,275,701	2,764,003	2,044,126	15,083,830	Sheet 3	(b)
13	Sub Total (Line 10+11+12)		65,885,922	18,498,037	5,754,167	90,138,126		
14	Total Investment Base Excluding CWIP (Lines 9+13)		2,205,969,792	496,142,396	610,817,038	3,312,929,225		(b)
15	Construction Work in Progress (13 mo. Average)	II(A)(1)(d)	134,757,788	-	4,772,177	139,529,965	Sheet 3	(a)
16	AFUDC Regulatory Liability (13 mo. Average)	II(A)(1)(i)	54,157,503	-	9,213,804	63,371,307	Sheet 3	(a)
17	Total Investment Base Including CWIP (Lines 14+15-16)		2,286,570,077	496,142,396	606,375,411	3,389,087,883		(b)
	II. REVENUE REQUIREMENTS							
18	Investment Return and Income Taxes - at 10.57% ROE	II(A)	264,520,044	56,861,888	67,616,224	388,998,156	Sheet 4a, Sheet 5a , Sheet 6a	(b)
19	Investment Return and Income Taxes - CWIP - at 10.57% ROE	II(A)	9,664,861	-	(491,679)	9,173,182	Sheet 4a, Sheet 5a , Sheet 6a	(b)
20	Depreciation Expense	II(B)	72,297,134	15,519,668	16,577,959	104,394,761	Sheet 7	(a)
21	Amortization of Loss on Reacquired Debt	II(C)	593,685	246,881	49,668	890,234	Sheet 7	(a)
22	Investment Tax Credit	II(D)	(428,304)	(4,852)	(35,604)	(468,760)	Sheet 7	(a)
23	Property Tax Expense	II(E)	45,144,822	18,087,310	18,717,332	81,949,464	Sheet 7	(a)
24	Payroll Tax Expense	II(F)	322,527	(4,083)	18,291	336,735	Sheet 7	(a)
25	Operation & Maintenance Expense	II(G)	37,849,988	10,282,288	6,368,294	54,500,570	Sheet 7	(a)
26	Administrative & General Expense	II(H)	44,355,620	11,829,739	9,984,711	66,170,070	Sheet 7	(b)
27	Transmission Support Expenses	II(I)	1,625,568	898,916	457,017	2,981,501	Sheet 8	(a)
28	Transmission Related Taxes and Fees Charge	II(J)	9,854,673	158,113	20,627	10,033,413	Note 1	(a)
29	Total Revenue Requirements (Line 18 thru 28)		485,800,618	113,875,868	119,282,840	718,959,326		(b)

Note 1 - Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment B.

Notes

(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247

(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

CL&P, PSNH, and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Under Changed Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For Costs in 2014
Sheet 3

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	
				FF1		FF1		FF1	
Line	Description	FF1 Reference	CL&P	Line	PSNH	Line	WMECO	Line	Notes
	Transmission Plant								
1	Transmission Plant		2,977,602,438	Sheet 9	648,561,975	Sheet 11	829,609,658	Sheet 13	(a)
2	CL&P Dispatch Center	Note 1	32,712		-		-		(a)
3	Net Transmission Plant (line 1-2)		2,977,569,726		648,561,975		829,609,658		
	General Plant								
4	General Plant	FF1 page 204 footnote	102,812,641	Line 99	58,369,540	Line 99	18,348,753	Line 99	(a)
5	CL&P General Dispatch Center	Note 1	15,870,872		-		-		(a)
6	Net General Plant (line 4-5)		86,941,769		58,369,540		18,348,753		
7	Transmission Plant Held for Future Use		35,612,990	Sheet 9	13,626,119	Sheet 11	750,000	Sheet 13	
	Transmission Accumulated Depreciation								
8	Transmission Accum. Depreciation	FF1 page 219	579,929,318	Line 25	117,852,509	Line 25	47,948,646	Line 25	(a)
9	CL&P Dispatch Center Accum. Depreciation	Note 1	(1,482,625)		-		-		(a)
10	Transmission Related General Plant Accum.Depreciation	FF1 page 219	26,085,325	Line 28	14,660,211	Line 28	3,971,742	Line 28	(a)
11	CL&P Dispatch Center General Accum. Depreciation	Note 1	3,717,252		-		-		(a)
12	Net Accumulated Depreciation (line 8-9+10-11)		603,780,016		132,512,720		51,920,388		
	Transmission Accumulated Deferred Taxes								
13	Accumulated Deferred Taxes (281 to 283)	FF1 page 274 & 276 footnote	451,817,902	Line 9 & Line 19	134,008,391	Line 9 & Line 19	213,650,889	Line 9 & Line 19	(a)
14	Accumulated Deferred Taxes (190)	FF1 page 234 footnote	59,128,935	Line 18	10,892,336	Line 18	12,549,258	Line 18	(a)
15	Reserve for Disputed Transactions	FF1 page 234 footnote	2,134,971	Line 18	-	Line 18	-	Line 18	(a)
16	CL&P Dispatch Center ADIT ("T" and General)	Note 1	3,585,862		-		-		(a)
17	Total (line 13-14+15-16)		391,238,076		123,116,055		201,101,631		
18	Unam. Loss on Reacquired Debt (189)	FF1 page 110 footnote	5,711,371	Line 81	2,107,937	Line 81	355,953	Line 81	(a)
	Other Regulatory Assets								
19	Unamortized Balance of Transmission Merger-Related Costs	Exhibit No. ES-220	10,729,989	Page 1 of 8, Line 4(C)	2,222,434	Page 3 of 8, Line 4(C)	2,914,814	Page 4 of 8, Line 4(C)	(b)
20	FAS 106 (FASB ASC 960/962)	FF1 page 232, 232.1, 232.1 footnote	(9,267)	Line 27	282,181	Line 15	3,119	Line 1	(a)
21	FAS 109 (FASB ASC 740)	FF1 page 232, 232.1, 232.1 footnote	22,783,548	Line 7	8,112,367	Line 1	6,178,066	Line 9	(a)
22	Other Regulatory Liabilities	FF1 page 278 footnote	4,238,164	Line 3	9,419	Line 1	75,473	Line 5	(a)
23	Total (line 19+20-21)		29,266,106		10,607,563		9,020,526		
24	Transmission Prepayments (165)	FF1 page 110 Footnote	19,487,085	Line 57	4,911,873	Line 57	642,737	Line 57	(a)
25	Transmission Materials and Supplies	FF1 page 227 Footnote	36,123,136	Line 8	10,822,161	Line 8	3,067,304	Line 8	(a)
	Cash Working Capital								
26	Operation & Maintenance Expense	Sheet 7	37,849,988		10,282,288		6,368,294		(a)
27	Administrative & General Expense	Sheet 7	44,355,620		11,829,739		9,984,711		(c)
28	Subtotal (line 25+26)		82,205,608		22,112,027		16,353,005		(c)
29	x 45 days/360 days	Section II.A.1(I) of Attachment NU-H	0.125		0.125		0.125		(a)
30	Total current Year End (line 27*28)		10,275,701		2,764,003		2,044,126		(c)
31	Prior Year End Cash Working Capital	Note 1	10,275,701		2,764,003		2,044,126		(a)
32	Average Cash Working Capital [(line 29+30)/2]		10,275,701		2,764,003		2,044,126		(c)
33	Construction Work in Progress (13 mo. avg.)	**Attachment A1**	134,757,788		-		4,772,177		(a)
34	AFUDC Regulatory Liability (13 mo. avg.)	**Attachment A1**	54,157,503		-		9,213,804		(a)

Note 1 - Reflects actual information per Eversource's accounting records.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset
(c) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light & Power Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Under Changed Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For Costs in 2014
Sheet 4a

	(A)	(B) YEAR END CAPITALIZATION		(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL		(E) = (C) x (D) WEIGHTED COST OF CAPITAL	(F) = (E) Equity Only EQUITY PORTION
1	LONG-TERM DEBT	$ 2,579,060,322	Note 2	45.78%	5.36%	Note 2	2.45%	
2	PREFERRED STOCK	$ 116,868,097	Note 2	2.07%	4.80%	Note 2	0.10%	0.10%
3	COMMON EQUITY	$ 2,938,441,767	Note 2	52.15%	10.57%	Note 1	5.51%	5.51%
4	TOTAL	$ 5,634,370,186		100.00%			8.06%	5.61%

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 8.06%

(b) Federal Income Tax = ((R.O.E. + (Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate)) / Total Inv. Base (a)) * Federal Income Tax Rate)

	Source	Line 4, Col. (F)		Sheet 7		FF1 page 336 ln. 7b + 10b footnotes		For Costs in 2014		Federal Corporate Tax Rate
6	= ((	5.61%	+ (	(428,304)	+	2,307,409	) /	2,286,570,077	) *	35.00%)
7			(	1	-	35.00% Federal Corporate Tax Rate	)			

8 = 3.0650%

(c) State Income Tax = ((R.O.E. + (Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate)) / Total Inv. Base) + Federal Income Tax) * (State Income Tax Rate)

	Source	Line 4, Col. (F)		Sheet 7		FF1 page 336 ln. 7b + 10b footnotes		For Costs in 2014		Line 8, Col. (B)		Connecticut Corporate Tax Rate
9	= ((	5.61%	+ (	(428,304)	+	2,307,409	) /	2,286,570,077	) +	3.0650%	) * (	9.00%)
10			(	1	-	9.00% Connecticut Corporate Tax Rate	)					

11 = 0.8661%

12 (a)+(b)+(c) Cost of Capital Rate = 11.9911%

		Total Transmission	-	CWIP	=	Total T - Excluding CWIP	Reference
13	INVESTMENT BASE	$2,286,570,077		$80,600,285		$2,205,969,792	For Costs in 2014
14	x Cost of Capital Rate	11.9911%		11.9911%		11.9911%	Line 12
15	= Investment Return and Income Taxes	$274,184,904		$9,664,861		$264,520,044	

Note 1 - ROE per FERC Order in Docket No. ER04-157 dated March 24, 2008.
Note 2 - Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes

(a) Proposed revisions to "Total Inv. Base" reflects the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the addition of the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

Source of all other information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247

Public Service Company of New Hampshire
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Under Changed Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For Costs in 2014
Sheet 5a

	(A)	(B) YEAR END CAPITALIZATION		(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL		(E) = (C) x (D) WEIGHTED COST OF CAPITAL	(F) = (E) Equity Only EQUITY PORTION
1	LONG-TERM DEBT	$ 1,070,020,120	Note 2	46.56%	4.15%	Note 2	1.93%	
2	PREFERRED STOCK	$ -	Note 2	0.00%	0.00%	Note 2	0.00%	0.00%
3	COMMON EQUITY	$ 1,228,095,985	Note 2	53.44%	10.57%	Note 1	5.65%	5.65%
4	TOTAL	$ 2,298,116,105		100.00%			7.58%	5.65%

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 7.58%

(b) Federal Income Tax = ((R.O.E. + (Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / Total Inv. Base) * Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

Source: Sheet 7; FF1 page 336 ln. 7b + 10b footnotes; For Costs in 2014; Federal Corporate Tax Rate

6 = ((5.65% + ((4,852) + 230,083) / 496,142,396) * 35.00%)
7 (1 - 35.00%) Federal Corporate Tax Rate

8 = 3.0668%

(c) State Income Tax = ((R.O.E. + (Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / Total Inv. Base) + Federal Income Tax) * (State Income Tax Rate) / (1 - State Income Tax Rate)

Source: Sheet 7; FF1 page 336 ln. 7b + 10b footnotes; For Costs in 2014; New Hampshire Corporate Tax Rate

9 = ((5.65% + ((4,852) + 230,083) / 496,142,396) + 3.0668%) * (8.50%)
10 (1 - 8.50%) New Hampshire Corporate Tax Rate

11 = 0.8140%

12 (a)+(b)+(c) Cost of Capital Rate = 11.4608%

		Total Transmission	- CWIP	= Total T - Excluding CWIP	Reference
13	INVESTMENT BASE	$496,142,396	-	$496,142,396	For Costs in 2014
14	x Cost of Capital Rate	11.4608%	11.4608%	11.4608%	Line 12
15	= Investment Return and Income Taxes	$56,861,888	-	$56,861,888	

Note 1 - ROE per FERC Order in Docket No. ER04-157 dated March 24, 2008.
Note 2 - Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes

(a) Proposed revisions to "Total Inv. Base" reflects the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the addition of the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

Source of all other information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247

Western Massachusetts Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Under Changed Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For Costs in 2014
Sheet 6a

	(A)	(B) YEAR END CAPITALIZATION		(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL		(E) = (C) x (D) WEIGHTED COST OF CAPITAL	(F) = (E) Equity Only EQUITY PORTION
1	LONG-TERM DEBT	$ 567,833,428	Note 2	49.55%	4.31%	Note 2	2.14%	
2	PREFERRED STOCK	$ -	Note 2	0.00%	0.00%	Note 2	0.00%	0.00%
3	COMMON EQUITY	$ 578,162,814	Note 2	50.45%	10.57%	Note 1	5.33%	5.33%
4	TOTAL	$ 1,145,996,242		100.00%			7.47%	5.33%

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 7.47%

(b) Federal Income Tax = ((R.O.E. + (Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / Total Inv. Base) * Federal Income Tax Rate)
(1 - Federal Income Tax Rate)

	Source		R.O.E.		Sheet 7		FF1 page 336 ln. 7b + 10b footnotes		For Costs in 2014		Federal Corporate Tax Rate	
6		= ((	5.33%	+ (	(35,604)	+	186,099	) /	606,375,411	) *	35.00%	)
7				(	1	-	35.00% Federal Corporate Tax Rate	)				
8		=	2.8834%									

(c) State Income Tax = ((R.O.E. + (Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / Total Inv. Base) + Federal Income Tax) * (State Income Tax Rate)
(1 - State Income Tax Rate)

	Source		R.O.E.		Sheet 7		FF1 page 336 ln. 7b + 10b footnotes		For Costs in 2014				Massachusetts Corporate Tax Rate	
9		= ((	5.33%	+ (	(35,604)	+	186,099	) /	606,375,411	) +	2.8834%	) * (	8.00%	)
10				(	1	-	8.00% Massachusetts Corporate Tax Rate	)						
11		=	0.7164%											

12 (a)+(b)+(c) Cost of Capital Rate = 11.0698%

		Total Transmission	-	CWIP	=	Total T - Excluding CWIP	Reference
13	INVESTMENT BASE	$606,375,411		($4,441,627)		$610,817,038	For Costs in 2014
14	x Cost of Capital Rate	11.0698%		11.0698%		11.0698%	Line 12
15	= Investment Return and Income Taxes	$67,124,545		($491,679)		$67,616,224	

Note 1 - ROE per FERC Order in Docket No. ER04-157 dated March 24, 2008.
Note 2 - Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes

(a) Proposed revisions to "Total Inv. Base" reflects the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the addition of the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

Source of all other information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247

CL&P, PSNH, and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Under Changed Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For Costs in 2014
Sheet 7

Line	(A) Description	(B) FF1 Reference	(C) CL&P Year End	(D) FF1 Line	(E) PSNH Year End	(F) FF1 Line	(G) WMECO Year End	(H) FF1 Line	Notes
	Depreciation Expense								
1	Transmission Depreciation	FF1 page 336	69,626,166	7b	12,792,512	7b	15,972,687	7b	(a)
2	General Depreciation	FF1 page 336 footnote	4,980,574	10b	2,727,156	10b	789,658	10b	(a)
3	AFUDC Regulatory Credit	Attachment A1	1,145,364		-		184,386		(a)
4	Dispatch Plant Depreciation ("T" and General)	Note 1	1,164,242		-		-		(a)
5	Net Depreciation Expense (line 1+2-3-4)		72,297,134		15,519,668		16,577,959		
6	Amortization of Loss on Reacquired Debt	FF1 page 114 footnote	593,685	64c	246,881	64c	49,668	64c	(a)
	Investment Tax Credits								
7	Amortization of Investment Tax Credits	FF1 page 266 footnote	(428,304)	8f	(4,852)	8f	(35,604)	8f	(a)
8	Dispatch Center ITC ("T" and General)	Note 1	-		-		-		(a)
9	Net Investment Tax Credit (line 7-8)		(428,304)		(4,852)		(35,604)		
	Property Taxes								
10	Transmission Property Taxes	FF1 page 262 footnote	45,370,701	25i	18,087,310	Note 3	18,717,332	32i	(a)
11	General Property Taxes (included in line 10)	Note 2	-		-		-		(a)
12	Dispatch Center Property Taxes ("T" and General)	Note 1	225,879		-		-		(a)
13	Net Property Taxes (line 10+11-12)		45,144,822		18,087,310		18,717,332		
	Payroll Taxes:								
14	Federal Unemployment	FF1 page 262 footnote	5,226	3i	(51)	2i	283	3i	(a)
15	FICA	FF1 page 262 footnote	233,351	5i	(3,062)	4i	13,202	5i	(a)
16	Medicare	FF1 page 262 footnote	65,613	9i	(816)	7i	3,757	9i	(a)
17	CT Unemployment	FF1 page 262, 262.1, 262 footnote	16,786	15i	(128)	7i	852	13i	(a)
18	DC Unemployment	FF1 page 262.1 footnote	11	14i	-		1	6i	(a)
19	FL Unemployment	FF1 page 262.1 footnote	1	18i	-	27i	-	10i	(a)
20	MI Unemployment	FF1 page 262.1 footnote	6	22i	-	31i	-	14i	(a)
21	MA Unemployment	FF1 page 262, 262.1, 262 footnote	(285)	32i	2	15i	69	22i	(a)
22	MA Universal Health	FF1 page 262, 262.1, 262 footnote	64	33i	(1)	16i	19	27i	(a)
23	NH Unemployment	FF1 page 262.1, 262, 262 footnote	1,754	4i	(27)	14i	108	37i	(a)
24	NJ Unemployment	FF1 page 262 footnote	-		-		-		(a)
25	NY Unemployment	FF1 page 262.1 footnote	-	10i	-		-		(a)
26	Total Payroll Tax Exp (sum of line 14 through 25)		322,527		(4,083)		18,291		
	Transmission Operation and Maintenance								
27	Operation and Maintenance	FF1 page 321	77,432,007	112	51,082,852	112	20,725,279	112	(a)
28	Transmission of Electricity by Others - #565	FF1 page 321	21,727,966	96	37,174,569	96	13,174,678	96	(a)
29		FF1 page 321		84		84		84	(a)
30	Account 561.1	FF1 page 321	3,245,594	85	653,575	85	12,368	85	(a)
31	Account 561.2	FF1 page 321	5,212,556	86	474,690	86	50,569	86	(a)
32	Account 561.3	FF1 page 321	2,238,612	87	36,962	87	13,262	87	(a)
33	Account 561.4	FF1 page 321	7,157,291	88	2,460,768	88	1,106,108	88	(a)
34	Station Expenses & Rents - #562 / #567	FF1 page 321	-	93+98	-	93+98	-	93+98	(a)
35	Net O&M (line 27 - [sum lines 28 through 34])		37,849,988		10,282,288		6,368,294	Line 23 (H)	
	Transmission Administrative and General								
36	Administrative and General	FF1 page 320 footnote	37,202,294	197	10,348,117	197	8,041,502	197	(a)
37	Transmission Merger-Related Costs	Exhibit No. ES-220	7,153,326	Page 1 of 8, Line 2(C)	1,481,622	Page 3 of 8, Line 2(C)	1,943,209	Page 4 of 8, Line 2(C)	(b)
38	Public Education Expenses	FF1 page 114 footnote	-	49	-	49	-	49	(a)
39	Total Administrative and General (line 36+37)		44,355,620		11,829,739		9,984,711		(b)

Note 1 - Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.
Note 2 - Reflects actual information per the Company's accounting records.
Note 3 -This includes local New Hampshire, Vermont, and Maine property taxes (Page 262 ln, 23i, footnote + Page 262 ln, 30i, footnote + Page 262.1 ln, 2i, footnote).

Notes
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Exhibit No. ES-224
Schedule 5

Category A Revenue Requirements under the Changed Rates for 2018

Eversource Energy Service Company

CL&P, PSNH, and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21 ES (Formerly Schedule 21 NU) Revenue Requirement Under Changed Rates
Under Schedule ES H (Formerly Schedule NU H)
For the Calendar year 2018

	(A)	(B)	(C)	(D)	(E)	(F) (C)+(D)+(E)
Line	**Description**	**Reference**	**CL&P**	**PSNH**	**WMECO**	**Total NU**
1	2014 Actual Schedule 21-ES, Category A Revenue Requirement		$ 484,947,414 (1)	$ 113,706,062 (2)	$ 119,067,731 (3)	$ 717,721,207
2	Estimated 2015 Schedule 21-ES, Category A Plant Additions	(4)	$ 278,000,000	$ 123,000,000	$ 100,000,000	$ 501,000,000
3	Carrying Charge Factor (CCF)	Exhibit No. ES-224, Schedule 2, Page 2 of 7, Note (c)	15.70%	17.29%	14.16%	15.78%
4	2015 Incremental Estimated Schedule 21-ES, Category A Revenue Requirement	Line 2 x 3	43,646,000	21,266,700	14,160,000	79,072,700
5	2015 Incremental Estimated Schedule 21-ES, Category A CWIP Revenue Requirements	(4)	$ 6,218,000	$ -	$ (999,000)	$ 5,219,000
6	Total Estimated Schedule 21-ES, Category A Revenue Requirement for 2015	Line 1 + 4 + 5	$ 534,811,414	$ 134,972,762	$ 132,228,731	$ 802,012,907
7	Estimated 2016 Schedule 21-ES, Category A Plant Additions	(4)	$ 72,000,000	$ 117,000,000	$ 92,000,000	$ 281,000,000
8	Carrying Charge Factor (CCF)	Line 3	15.70%	17.29%	14.16%	15.86%
9	2016 Incremental Estimated Schedule 21-ES, Category A Revenue Requirement	Line 7 x 8	11,304,000	20,229,300	13,027,200	44,560,500
10	Total Estimated Schedule 21-ES, Category A Revenue Requirement for 2016	Line 6 + 9	$ 546,115,414	$ 155,202,062	$ 145,255,931	$ 846,573,407 (5)

Notes:
(1) Exhibit ES 224, Schedule 5, Page 2 of 7, Line 29(C)
(2) Exhibit ES 224, Schedule 5, Page 2 of 7, Line 29(D)
(3) Exhibit ES 224, Schedule 5, Page 2 of 7, Line 29(E)
(4) Based on Eversource's Forecast
(5) The revenue requirements calculations for the calendar year 2016 (including any forecast for 2016) are used as an estimate for the revenue requirements for 2018, which are used to calculate the revenue impact of the proposed cost recovery.

CL&P, PSNH, and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Under Changed Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For Costs in 2014
Sheet 2a

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	
Line	I. INVESTMENT BASE	Attachment H Reference Section:	CL&P	PSNH	WMECO	Total	Source	**Notes**
1	Transmission Plant	II(A)(1)(a)	2,977,569,726	648,561,975	829,609,658	4,455,741,359	Sheet 3	(a)
2	General Plant	II(A)(1)(b)	86,941,769	58,369,540	18,348,753	163,660,062	Sheet 3	(a)
3	Plant Held For Future Use	II(A)(1)(c)	35,612,990	13,626,119	750,000	49,989,109	Sheet 3	(a)
4	Total Plant (Lines 1+2+3)		3,100,124,485	720,557,634	848,708,411	4,669,390,530		
5	Accumulated Depreciation	II(A)(1)(e)	603,780,016	132,512,720	51,920,388	788,213,124	Sheet 3	(a)
6	Accumulated Deferred Income Taxes	II(A)(1)(f)	391,238,076	123,116,055	201,101,631	715,455,762	Sheet 3	(a)
7	Loss On Reacquired Debt	II(A)(1)(g)	5,711,371	2,107,937	355,953	8,175,261	Sheet 3	(a)
8	Other Regulatory Assets	II(A)(1)(h)	22,112,780	9,125,940	7,077,317	38,316,037	Sheet 3	(b)
9	Net Investment (Line 4-5-6+7+8)		2,132,930,544	476,162,736	603,119,662	3,212,212,942		(b)
10	Prepayments	II(A)(1)(j)	19,487,085	4,911,873	642,737	25,041,695	Sheet 3	(a)
11	Materials & Supplies	II(A)(1)(k)	36,123,136	10,822,161	3,067,304	50,012,601	Sheet 3	(a)
12	Cash Working Capital	II(A)(1)(l)	10,275,701	2,764,003	2,044,126	15,083,830	Sheet 3	(b)
13	Sub Total (Line 10+11+12)		65,885,922	18,498,037	5,754,167	90,138,126		
14	Total Investment Base Excluding CWIP (Lines 9+13)		2,198,816,466	494,660,773	608,873,829	3,302,351,068		(b)
15	Construction Work in Progress (13 mo. Average)	II(A)(1)(d)	134,757,788	-	4,772,177	139,529,965	Sheet 3	(a)
16	AFUDC Regulatory Liability (13 mo. Average)	II(A)(1)(i)	54,157,503	-	9,213,804	63,371,307	Sheet 3	(a)
17	Total Investment Base Including CWIP (Lines 14+15-16)		2,279,416,751	494,660,773	604,432,202	3,378,509,726		(b)
	II. REVENUE REQUIREMENTS							
18	Investment Return and Income Taxes - at 10.57% ROE	II(A)	263,666,679	56,692,082	67,401,115	387,759,876	Sheet 4a, Sheet 5a , Sheet 6a	(b)
19	Investment Return and Income Taxes - CWIP - at 10.57% ROE	II(A)	9,665,022	-	(491,679)	9,173,343	Sheet 4a, Sheet 5a , Sheet 6a	(b)
20	Depreciation Expense	II(B)	72,297,134	15,519,668	16,577,959	104,394,761	Sheet 7	(a)
21	Amortization of Loss on Reacquired Debt	II(C)	593,685	246,881	49,668	890,234	Sheet 7	(a)
22	Investment Tax Credit	II(D)	(428,304)	(4,852)	(35,604)	(468,760)	Sheet 7	(a)
23	Property Tax Expense	II(E)	45,144,822	18,087,310	18,717,332	81,949,464	Sheet 7	(a)
24	Payroll Tax Expense	II(F)	322,527	(4,083)	18,291	336,735	Sheet 7	(a)
25	Operation & Maintenance Expense	II(G)	37,849,988	10,282,288	6,368,294	54,500,570	Sheet 7	(a)
26	Administrative & General Expense	II(H)	44,355,620	11,829,739	9,984,711	66,170,070	Sheet 7	(b)
27	Transmission Support Expenses	II(I)	1,625,568	898,916	457,017	2,981,501	Sheet 8	(a)
28	Transmission Related Taxes and Fees Charge	II(J)	9,854,673	158,113	20,627	10,033,413	Note 1	(a)
29	Total Revenue Requirements (Line 18 thru 28)		484,947,414	113,706,062	119,067,731	717,721,207		(b)

Note 1 - Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment B.

Notes

(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

CL&P, PSNH, and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Under Changed Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For Costs in 2014
Sheet 3

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	
				FF1		FF1		FF1	
Line	Description	**FF1 Reference**	CL&P	Line	PSNH	Line	WMECO	Line	Notes
	Transmission Plant								
1	Transmission Plant		2,977,602,438	Sheet 9	648,561,975	Sheet 11	829,609,658	Sheet 13	(a)
2	CL&P Dispatch Center	Note 1	32,712		-		-		(a)
3	Net Transmission Plant (line 1-2)		2,977,569,726		648,561,975		829,609,658		
	General Plant								
4	General Plant	FF1 page 204 footnote	102,812,641	Line 99	58,369,540	Line 99	18,348,753	Line 99	(a)
5	CL&P General Dispatch Center	Note 1	15,870,872		-		-		(a)
6	Net General Plant (line 4-5)		86,941,769		58,369,540		18,348,753		
7	Transmission Plant Held for Future Use		35,612,990	Sheet 9	13,626,119	Sheet 11	750,000	Sheet 13	
	Transmission Accumulated Depreciation								
8	Transmission Accum. Depreciation	FF1 page 219	579,929,318	Line 25	117,852,509	Line 25	47,948,646	Line 25	(a)
9	CL&P Dispatch Center Accum. Depreciation	Note 1	(1,482,625)		-		-		(a)
10	Transmission Related General Plant Accum.Depreciation	FF1 page 219	26,085,325	Line 28	14,660,211	Line 28	3,971,742	Line 28	(a)
11	CL&P Dispatch Center General Accum. Depreciation	Note 1	3,717,252		-		-		(a)
12	Net Accumulated Depreciation (line 8-9+10-11)		603,780,016		132,512,720		51,920,388		
	Transmission Accumulated Deferred Taxes								
13	Accumulated Deferred Taxes (281 to 283)	FF1 page 274 & 276 footnote	451,817,902	Line 9 & Line 19	134,008,391	Line 9 & Line 19	213,650,889	Line 9 & Line 19	(a)
14	Accumulated Deferred Taxes (190)	FF1 page 234 footnote	59,128,935	Line 18	10,892,336	Line 18	12,549,258	Line 18	(a)
15	Reserve for Disputed Transactions	FF1 page 234 footnote	2,134,971	Line 18	-	Line 18	-	Line 18	(a)
16	CL&P Dispatch Center ADIT ("T" and General)	Note 1	3,585,862		-		-		(a)
17	Total (line 13-14+15-16)		391,238,076		123,116,055		201,101,631		
18	Unam. Loss on Reacquired Debt (189)	FF1 page 110 footnote	5,711,371	Line 81	2,107,937	Line 81	355,953	Line 81	(a)
	Other Regulatory Assets								
19	Unamortized Balance of Transmission Merger-Related Costs	Exhibit No. ES-220	3,576,663	Page 1 of 8, Line 4(D)	740,811	Page 3 of 8, Line 4(D)	971,605	Page 4 of 8, Line 4(D)	(b)
20	FAS 106 (FASB ASC 960/962)	FF1 page 232, 232.1, 232.1 footnote	(9,267)	Line 27	282,181	Line 15	3,119	Line 1	(a)
21	FAS 109 (FASB ASC 740)	FF1 page 232, 232.1, 232.1 footnote	22,783,548	Line 7	8,112,367	Line 1	6,178,066	Line 9	(a)
22	Other Regulatory Liabilities	FF1 page 278 footnote	4,238,164	Line 3	9,419	Line 1	75,473	Line 5	(a)
23	Total (line 19+20-21)		22,112,780		9,125,940		7,077,317		
24	Transmission Prepayments (165)	FF1 page 110 Footnote	19,487,085	Line 57	4,911,873	Line 57	642,737	Line 57	(a)
25	Transmission Materials and Supplies	FF1 page 227 Footnote	36,123,136	Line 8	10,822,161	Line 8	3,067,304	Line 8	(a)
	Cash Working Capital								
26	Operation & Maintenance Expense	Sheet 7	37,849,988		10,282,288		6,368,294		(a)
27	Administrative & General Expense	Sheet 7	44,355,620		11,829,739		9,984,711		(c)
28	Subtotal (line 25+26)		82,205,608		22,112,027		16,353,005		(c)
29	x 45 days/360 days	Section II.A.1(l) of Attachment NU-H	0.125		0.125		0.125		(a)
30	Total current Year End (line 27*28)		10,275,701		2,764,003		2,044,126		(c)
31	Prior Year End Cash Working Capital	Note 1	10,275,701		2,764,003		2,044,126		(a)
32	Average Cash Working Capital [(line 29+30)/2]		10,275,701		2,764,003		2,044,126		(c)
33	Construction Work in Progress (13 mo. avg.)	**Attachment A1**	134,757,788		-		4,772,177		(a)
34	AFUDC Regulatory Liability (13 mo. avg.)	**Attachment A1**	54,157,503		-		9,213,804		(a)

Note 1 - Reflects actual information per Eversource's accounting records.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset
(c) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light & Power Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Under Changed Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For Costs in 2014
Sheet 4a

	(A)	(B) YEAR END CAPITALIZATION		(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL		(E) = (C) x (D) WEIGHTED COST OF CAPITAL	(F) = (E) Equity Only EQUITY PORTION
1	LONG-TERM DEBT	$ 2,579,060,322	Note 2	45.78%	5.36%	Note 2	2.45%	
2	PREFERRED STOCK	$ 116,868,097	Note 2	2.07%	4.80%	Note 2	0.10%	0.10%
3	COMMON EQUITY	$ 2,938,441,767	Note 2	52.15%	10.57%	Note 1	5.51%	5.51%
4	TOTAL	$ 5,634,370,186		100.00%			8.06%	5.61%

Cost of Capital Rate=

5	(a) Weighted Cost of Capital	=	8.06%											
	(b) Federal Income Tax	= ((	R.O.E.	+ (	Total Inv. (Tax Credit)	+	Eq. AFUDC of Deprec. Exp.	) /	Total Inv. Base (a)	) *	Federal Income Tax Rate	)		
				(	1	-	Federal Income Tax Rate	)						
	Source		Line 4, Col. (F)		Sheet 7		FF1 page 336 ln. 7b + 10b footnotes		For Costs in 2014		Federal Corporate Tax Rate			
6		= ((	5.61%	+ (	(428,304)	+	2,307,409	) /	2,279,416,751	) *	35.00%	)		
7				(	1	-	35.00%	)						
							Federal Corporate Tax Rate							
8		=	3.0652%											
	(c) State Income Tax	= ((	R.O.E.	+ (	Total Inv. (Tax Credit)	+	Eq. AFUDC of Deprec. Exp.	) /	Total Inv. Base	) +	Federal Income Tax	) * (	State Income Tax Rate	)
				(	1	-	State Income Tax Rate	)						
	Source		Line 4, Col. (F)		Sheet 7		FF1 page 336 ln. 7b + 10b footnotes		For Costs in 2014		Line 8, Col. (B)		Connecticut Corporate Tax Rate	
9		= ((	5.61%	+ (	(428,304)	+	2,307,409	) /	2,279,416,751	) +	3.0652%	) * (	9.00%	)
10				(	1	-	9.00%	)						
							Connecticut Corporate Tax Rate							
11		=	0.8661%											
12	(a)+(b)+(c) Cost of Capital Rate	=	11.9913%											

		Total Transmission	-	CWIP	=	Total T - Excluding CWIP	Reference
13	INVESTMENT BASE	$2,279,416,751		$80,600,285		$2,198,816,466	For Costs in 2014
14	x Cost of Capital Rate	11.9913%		11.9913%		11.9913%	Line 12
15	= Investment Return and Income Taxes	$273,331,701		$9,665,022		$263,666,679	

Note 1 - ROE per FERC Order in Docket No. ER04-157 dated March 24, 2008.
Note 2 - Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes

(a) Proposed revisions to "Total Inv. Base" reflects the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the addition of the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

Source of all other information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247

Public Service Company of New Hampshire
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Under Changed Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For Costs in 2014
Sheet 5a

	(A)	(B) YEAR END CAPITALIZATION		(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL		(E) = (C) x (D) WEIGHTED COST OF CAPITAL	(F) = (E) Equity Only EQUITY PORTION
1	LONG-TERM DEBT	$ 1,070,020,120	Note 2	46.56%	4.15%	Note 2	1.93%	
2	PREFERRED STOCK	$ -	Note 2	0.00%	0.00%	Note 2	0.00%	0.00%
3	COMMON EQUITY	$ 1,228,095,985	Note 2	53.44%	10.57%	Note 1	5.65%	5.65%
4	TOTAL	$ 2,298,116,105		100.00%			7.58%	5.65%

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 7.58%

(b) Federal Income Tax = ((R.O.E. + (Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / Total Inv. Base) * Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

	Source				Sheet 7		FF1 page 336 ln. 7b + 10b footnotes		For Costs in 2014		Federal Corporate Tax Rate
6		= ((	5.65%	+ (	(4,852)	+	230,083	) /	494,660,773	) *	35.00%)
7				(	1	-	35.00%	)			
							Federal Corporate Tax Rate				
8		=	3.0668%								

(c) State Income Tax = ((R.O.E. + (Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / Total Inv. Base) + Federal Income Tax) * (State Income Tax Rate) / (1 - State Income Tax Rate)

	Source				Sheet 7		FF1 page 336 ln. 7b + 10b footnotes		For Costs in 2014				New Hampshire Corporate Tax Rate
9		= ((	5.65%	+ (	(4,852)	+	230,083	) /	494,660,773	) +	3.0668%	) * (	8.50%)
10				(	1	-	8.50%	)					
							New Hampshire Corporate Tax Rate						
11		=	0.8140%										

12 (a)+(b)+(c) Cost of Capital Rate = 11.4608%

		Total Transmission	-	CWIP	=	Total T - Excluding CWIP	Reference
13	INVESTMENT BASE	$494,660,773		-		$494,660,773	For Costs in 2014
14	x Cost of Capital Rate	11.4608%		11.4608%		11.4608%	Line 12
15	= Investment Return and Income Taxes	$56,692,082		-		$56,692,082	

Note 1 - ROE per FERC Order in Docket No. ER04-157 dated March 24, 2008.
Note 2 - Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes

(a) Proposed revisions to "Total Inv. Base" reflects the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the addition of the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

Source of all other information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247

Western Massachusetts Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Under Changed Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For Costs in 2014
Sheet 6a

	(A)	(B) YEAR END CAPITALIZATION		(C) CAPITALIZATION RATIOS	(D) COST OF CAPITAL		(E) = (C) x (D) WEIGHTED COST OF CAPITAL	(F) = (E) Equity Only EQUITY PORTION
1	LONG-TERM DEBT	$ 567,833,428	Note 2	49.55%	4.31%	Note 2	2.14%	
2	PREFERRED STOCK	$ -	Note 2	0.00%	0.00%	Note 2	0.00%	0.00%
3	COMMON EQUITY	$ 578,162,814	Note 2	50.45%	10.57%	Note 1	5.33%	5.33%
4	TOTAL	$ 1,145,996,242		100.00%			7.47%	5.33%

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 7.47%

(b) Federal Income Tax = ((R.O.E. + (Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate)) / Total Inv. Base) * Federal Income Tax Rate)

	Source			Sheet 7		FF1 page 336 ln. 7b + 10b footnotes		For Costs in 2014		Federal Corporate Tax Rate	
6		= ((	5.33%	+ ((35,604)	+	186,099	) /	604,432,202	) *	35.00%	)
7				(1	-	35.00% Federal Corporate Tax Rate	)				
8		=	2.8834%								

(c) State Income Tax = ((R.O.E. + (Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate)) / Total Inv. Base) + Federal Income Tax) * (State Income Tax Rate)

	Source			Sheet 7		FF1 page 336 ln. 7b + 10b footnotes		For Costs in 2014				Massachusetts Corporate Tax Rate	
9		= ((	5.33%	+ ((35,604)	+	186,099	) /	604,432,202	) +	2.8834%	) * (	8.00%	)
10				(1	-	8.00% Massachusetts Corporate Tax Rate	)						
11		=	0.7164%										
12	(a)+(b)+(c) Cost of Capital Rate	=	11.0698%										

		Total Transmission	-	CWIP	=	Total T - Excluding CWIP	Reference
13	INVESTMENT BASE	$604,432,202		($4,441,627)		$608,873,829	For Costs in 2014
14	x Cost of Capital Rate	11.0698%		11.0698%		11.0698%	Line 12
15	= Investment Return and Income Taxes	$66,909,436		($491,679)		$67,401,115	

Note 1 - ROE per FERC Order in Docket No. ER04-157 dated March 24, 2008.
Note 2 - Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes

(a) Proposed revisions to "Total Inv. Base" reflects the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the addition of the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

Source of all other information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247

CL&P, PSNH, and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Under Changed Rates
Under Schedule ES-H (Formerly Schedule NU-H)
For Costs in 2014
Sheet 7

Line	(A) Description	(B) FF1 Reference	(C) CL&P Year End	(D) FF1 Line	(E) PSNH Year End	(F) FF1 Line	(G) WMECO Year End	(H) FF1 Line	Notes
	Depreciation Expense								
1	Transmission Depreciation	FF1 page 336	69,626,166	7b	12,792,512	7b	15,972,687	7b	(a)
2	General Depreciation	FF1 page 336 footnote	4,980,574	10b	2,727,156	10b	789,658	10b	(a)
3	AFUDC Regulatory Credit	Attachment A1	1,145,364		-		184,386		(a)
4	Dispatch Plant Depreciation ("T" and General)	Note 1	1,164,242		-		-		(a)
5	Net Depreciation Expense (line 1+2-3-4)		72,297,134		15,519,668		16,577,959		
6	Amortization of Loss on Reacquired Debt	FF1 page 114 footnote	593,685	64c	246,881	64c	49,668	64c	(a)
	Investment Tax Credits								
7	Amortization of Investment Tax Credits	FF1 page 266 footnote	(428,304)	8f	(4,852)	8f	(35,604)	8f	(a)
8	Dispatch Center ITC ("T" and General)	Note 1	-		-		-		(a)
9	Net Investment Tax Credit (line 7-8)		(428,304)		(4,852)		(35,604)		
	Property Taxes								
10	Transmission Property Taxes	FF1 page 262 footnote	45,370,701	25i	18,087,310	Note 3	18,717,332	32i	(a)
11	General Property Taxes (included in line 10)	Note 2	-		-		-		(a)
12	Dispatch Center Property Taxes ("T" and General)	Note 1	225,879		-		-		(a)
13	Net Property Taxes (line 10+11-12)		45,144,822		18,087,310		18,717,332		
	Payroll Taxes:								
14	Federal Unemployment	FF1 page 262 footnote	5,226	3i	(51)	2i	283	3i	(a)
15	FICA	FF1 page 262 footnote	233,351	5i	(3,062)	4i	13,202	5i	(a)
16	Medicare	FF1 page 262 footnote	65,613	9i	(816)	7i	3,757	9i	(a)
17	CT Unemployment	FF1 page 262, 262.1, 262 footnote	16,786	15i	(128)	7i	852	13i	(a)
18	DC Unemployment	FF1 page 262.1 footnote	11	14i	-		1	6i	(a)
19	FL Unemployment	FF1 page 262.1 footnote	1	18i	-	27i	-	10i	(a)
20	MI Unemployment	FF1 page 262.1 footnote	6	22i	-	31i	-	14i	(a)
21	MA Unemployment	FF1 page 262, 262.1, 262 footnote	(285)	32i	2	15i	69	22i	(a)
22	MA Universal Health	FF1 page 262, 262.1, 262 footnote	64	33i	(1)	16i	19	27i	(a)
23	NH Unemployment	FF1 page 262.1, 262, 262 footnote	1,754	4i	(27)	14i	108	37i	(a)
24	NJ Unemployment	FF1 page 262 footnote	-		-		-		(a)
25	NY Unemployment	FF1 page 262.1 footnote	-	10i	-		-		(a)
26	Total Payroll Tax Exp (sum of line 14 through 25)		322,527		(4,083)		18,291		
	Transmission Operation and Maintenance								
27	Operation and Maintenance	FF1 page 321	77,432,007	112	51,082,852	112	20,725,279	112	(a)
28	Transmission of Electricity by Others - #565	FF1 page 321	21,727,966	96	37,174,569	96	13,174,678	96	(a)
29		FF1 page 321		84		84		84	(a)
30	Account 561.1	FF1 page 321	3,245,594	85	653,575	85	12,368	85	(a)
31	Account 561.2	FF1 page 321	5,212,556	86	474,690	86	50,569	86	(a)
32	Account 561.3	FF1 page 321	2,238,612	87	36,962	87	13,262	87	(a)
33	Account 561.4	FF1 page 321	7,157,291	88	2,460,768	88	1,106,108	88	(a)
34	Station Expenses & Rents - #562 / #567	FF1 page 321	-	93+98	-	93+98	-	93+98	(a)
35	Net O&M (line 27 - [sum lines 28 through 34])		37,849,988		10,282,288		6,368,294	Line 23 (H)	
	Transmission Administrative and General								
36	Administrative and General	FF1 page 320 footnote	37,202,294	197	10,348,117	197	8,041,502	197	(a)
37	Transmission Merger-Related Costs	Exhibit No. ES-220	7,153,326	Page 1 of 8, Line 2(D)	1,481,622	Page 3 of 8, Line 2(D)	1,943,209	Page 4 of 8, Line 2(D)	(b)
38	Public Education Expenses	FF1 page 114 footnote	-	49	-	49	-	49	(a)
39	Total Administrative and General (line 36+37)		44,355,620		11,829,739		9,984,711		(b)

Note 1 - Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.
Note 2 - Reflects actual information per Eversource's accounting records.
Note 3 -This includes local New Hampshire, Vermont, and Maine property taxes (Page 262 ln, 23i, footnote + Page 262 ln, 30i, footnote + Page 262.1 ln, 2i, footnote).

Notes
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Exhibit No. ES-225
Schedule 1

Summary of Impact on Schedule 21-NSTAR's Revenue Requirements under Attachment D to the ISO-NE OATT (3-year amortization)

Eversource Energy Service Company

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-NSTAR Revenue Requirement Comparison Under Present and Changed Rates
Under Attachment D
For the Calendar Year 2016-2018

Line	(A) Description	(B) Net Revenue Requirements under the Present Rates in Attachment D		(C) Net Revenue Requirements under the Current Rates in Attachment D		(D) = (C) - (B) Difference (7) (Rounded to '000s)	(E) = (D)/(B) % Difference
1	2016 Estimated Attachment D Revenue Requirements	$ 115,159,162	(1)	$ 115,963,442	(4)	$ 804,000	0.7%
2	2017 Estimated Attachment D Revenue Requirements	$ 115,159,162	(2)	$ 115,885,129	(5)	$ 726,000	0.6%
3	2018 Estimated Attachment D Revenue Requirements	$ 115,159,162	(3)	$ 115,810,110	(6)	$ 651,000	0.6%

Notes:
(1) Exhibit No. ES-225, Schedule 1, Page 2 of 4, Line 5(B)
(2) Exhibit No. ES-225, Schedule 1, Page 3 of 4, Line 5(B)
(3) Exhibit No. ES-225, Schedule 1, Page 4 of 4, Line 5(B)
(4) Exhibit No. ES-225, Schedule 1, Page 2 of 4, Line 5(C)
(5) Exhibit No. ES-225, Schedule 1, Page 3 of 4, Line 5(C)
(6) Exhibit No. ES-225, Schedule 1, Page 4 of 4, Line 5(C)
(7) In connection with the three-year amortization alternative (with the proposed effective date of June 1, 2016), Eversource is showing the revenue impact for the thirty-six month period June 1, 2016 through May 31, 2019. Eversource is using calendar year revenue requirement calculations as estimates for the thirty-six month period beginning June 1, 2016. See Cooper Testimony Exhibit No. ES-200.

	2016	2017	2018	2019	Total
The amounts for each year are as follows:	$ 469,000	$ 759,000	$ 682,000	$ 271,000	$ 2,181,000

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-NSTAR Revenue Requirement Comparison Under Present and Changed Rates
Under Attachment D
For the Calendar Year 2016

Line	(A) Description		(B) Net Revenue Requirements under the Present Rates in Attachment D			(C) Net Revenue Requirements under the Changed Rates in Attachment D	
1	Total Schedule 21-NSTAR Revenue Requirements	$	345,401,471	(2)	$	350,179,360	(3)
2	Regional Network Service (RNS) Revenue Credits	$	216,750,485	(4)	$	220,691,094	(5)
3	ISO-NE Scheduling and Dispatch ("S&D") Revenues	$	5,576,120	(1)	$	5,609,120	(6)
4	Other Revenue Credits	$	7,915,704	(1)	$	7,915,704	(1)
5	Net Local Network Service Revenue Requirements *(Line 1 - 2 - 3 - 4)*	$	115,159,162		$	115,963,442	

Notes:
(1) Source of information is the NSTAR Annual Informational Filing submitted to FERC on August 14, 2015 in Docket No. ER07-549 and ER09-1243.
(2) Exhibit No. ES-225, Schedule 2, Page 1 of 5, Line 10(C)
(3) Exhibit No. ES-225, Schedule 3, Page 1 of 5, Line 10(C)

(4)

Line	Description		Amount		Reference
6	2014 RNS Revenue Credits under Present Rates	$	173,183,026		(1)
7	Plus: 2015 Forecasted Incremental Estimated PTF Revenue Credits		20,279,943		Exhibit No. ES-222, Schedule 2, Page 1 of 5, Line 4(c)
8	Plus: 2016 Forecasted Incremental Estimated PTF Revenue Credits		24,863,766		Exhibit No. ES-222, Schedule 2, Page 1 of 5, Line 9(c)
9	Less: 2015 Impact on RNS Revenue Credits due to 50 basis points		708,100		(a)
10	Less: 2016 Impact on RNS Revenue Credits due to 50 basis points		868,150		(a)
11	2016 RNS Revenue Credits under Present Rates (Lines 6 + 7 + 8 - 9 - 10)	$	216,750,485	To Line 2(B)	

(5)

Line	Description		Amount	Reference
12	RNS Revenue Credits under Present Rates	$	216,750,485	Line 2(B)
13	Plus: Incremental Estimated PTF Revenue Requirements		3,973,000	Exhibit No. ES-222, Schedule 1, Page 1 of 1, Line 1(D)
14	Less: Impact on RNS Revenue Credits due to 50 basis points		32,391	Exhibit No. ES-222, Schedule 3, Page 3 of 5, Line 46, Col.C **Less** Exhibit No. ES-222, Schedule 2, Page 3 of 5, Line 46, Col.C
9	RNS Revenue Credits under Proposed Language *(Lines 6 + 7 - 8)*	$	220,691,094	To Line 2(C)

(6)

Line	Description		Amount	Reference
10	S&D Revenue Credits under Present Rates	$	5,576,120	Line 3(B)
11	Incremental Estimated PTF Revenue Requirements	$	33,000	Exhibit No. ES-223, Schedule 1, Page 1 of 1, Line 1(D)
12	S&D Revenue Credits under Changed Rates (Line 10 + 11)	$	5,609,120	To Line 3(C)

(a)

Line	Description		2015	Below References from Exhibit No. ES-222 Schedule 2		2016	Below References from Exhibit No. ES-222 Schedule 2
13	PTF Plant Additions	$	146,000,000	Page 1 of 5, Line 2(C)	$	179,000,000	Page 1 of 5, Line 7(C)
14	Cost of Capital Rate for 50bp Incentive		0.4850%	Page 3 of 5, Line 42(Col. C)		0.4850%	Page 3 of 5, Line 42(Col. C)
15	Total (Lines 19 x 20)	$	708,100	To Line 9(B)	$	868,150	To Line 10(B)

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-NSTAR Revenue Requirement Comparison Under Present and Changed Rates
Under Attachment D
For the Calendar Year 2017

Line	(A) Description		(B) Net Revenue Requirements under the Present Rates in Attachment D			(C) Net Revenue Requirements under the Changed Rates in Attachment D	
1	Total Schedule 21-NSTAR Revenue Requirements	$	345,401,471	(2)	$	349,723,290	(3)
2	Regional Network Service (RNS) Revenue Credits	$	216,750,485	(4)	$	220,316,337	(5)
3	ISO-NE Scheduling and Dispatch ("S&D") Revenues	$	5,576,120	(1)	$	5,606,120	(6)
4	Other Revenue Credits	$	7,915,704	(1)	$	7,915,704	(1)
5	Net Local Network Service Revenue Requirements *(Line 1 - 2 - 3 - 4)*	$	115,159,162		$	115,885,129	

Notes:
(1) Source of information is the NSTAR Annual Informational Filing submitted to FERC on August 14, 2015 in Docket No. ER07-549 and ER09-1243.
(2) Exhibit No. ES-225, Schedule 2, Page 1 of 5, Line 10(C)
(3) Exhibit No. ES-225, Schedule 3, Page 1 of 5, Line 10(C)

(4)

Line	Description		Amount	Source
6	2014 RNS Revenue Credits under Present Rates	$	173,183,026	(1)
7	Plus: 2015 Forecasted Incremental Estimated PTF Revenue Credits		20,279,943	Exhibit No. ES-222, Schedule 2, Page 1 of 5, Line 4(c)
8	Plus: 2016 Forecasted Incremental Estimated PTF Revenue Credits		24,863,766	Exhibit No. ES-222, Schedule 2, Page 1 of 5, Line 9(c)
9	Less: 2015 Impact on RNS Revenue Credits due to 50 basis points		708,100	Exhibit No. ES-225, Schedule 1, Page 2 of 4, Line 15(B)
10	Less: 2016 Impact on RNS Revenue Credits due to 50 basis points		868,150	Exhibit No. ES-225, Schedule 1, Page 2 of 4, Line 15(C)
11	2016 RNS Revenue Credits under Present Rates (Lines 6 + 7 + 8 - 9 - 10)	$	216,750,485	To Line 2(B)

(5)

Line	Description		Amount	Source
12	RNS Revenue Credits under Present Rates	$	216,750,485	Line 2(B)
13	Plus: Incremental Estimated PTF Revenue Requirements		3,583,000	Exhibit No. ES-222, Schedule 1, Page 1 of 1, Line 2(D)
14	Less: Impact on RNS Revenue Credits due to 50 basis points		17,148	Exhibit No. ES-222, Schedule 4, Page 3 of 5, Line 46, Col.C **Less** Exhibit No. ES-222, Schedule 2, Page 3 of 5, Line 46, Col.C
15	RNS Revenue Credits under Proposed Language *(Lines 6 + 7 - 8)*	$	220,316,337	To Line 2(C)

(6)

Line	Description		Amount	Source
16	S&D Revenue Credits under Present Rates	$	5,576,120	Line 3(B)
17	Incremental Estimated PTF Revenue Requirements	$	30,000	Exhibit No. ES-223, Schedule 1, Page 1 of 1, Line 1(D)
18	S&D Revenue Credits under Changed Rates (Line 10 + 11)	$	5,606,120	To Line 3(C)

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-NSTAR Revenue Requirement Comparison Under Present and Changed Rates
Under Attachment D
For the Calendar Year 2018

Line	(A) Description	(B) Net Revenue Requirements under the Present Rates in Attachment D		(C) Net Revenue Requirements under the Changed Rates in Attachment D	
1	Total Schedule 21-NSTAR Revenue Requirements	$ 345,401,471	(2)	$ 349,268,513	(3)
2	Regional Network Service (RNS) Revenue Credits	$ 216,750,485	(4)	$ 219,940,579	(5)
3	ISO-NE Scheduling and Dispatch ("S&D") Revenues	$ 5,576,120	(1)	$ 5,602,120	(6)
4	Other Revenue Credits	$ 7,915,704	(1)	$ 7,915,704	(1)
5	Net Local Network Service Revenue Requirements *(Line 1 - 2 - 3 - 4)*	$ 115,159,162		$ 115,810,110	

Notes:
(1) Source of information is the NSTAR Annual Informational Filing submitted to FERC on August 14, 2015 in Docket No. ER07-549 and ER09-1243.
(2) Exhibit No. ES-225, Schedule 2, Page 1 of 5, Line 10(C)
(3) Exhibit No. ES-225, Schedule 3, Page 1 of 5, Line 10(C)

(4)

Line	Description	Amount	Source
6	2014 RNS Revenue Credits under Present Rates	$ 173,183,026	(1)
7	Plus: 2015 Forecasted Incremental Estimated PTF Revenue Credits	20,279,943	Exhibit No. ES-222, Schedule 2, Page 1 of 5, Line 4(c)
8	Plus: 2016 Forecasted Incremental Estimated PTF Revenue Credits	24,863,766	Exhibit No. ES-222, Schedule 2, Page 1 of 5, Line 9(c)
9	Less: 2015 Impact on RNS Revenue Credits due to 50 basis points	708,100	Exhibit No. ES-225, Schedule 1, Page 2 of 4, Line 15(B)
10	Less: 2016 Impact on RNS Revenue Credits due to 50 basis points	868,150	Exhibit No. ES-225, Schedule 1, Page 2 of 4, Line 15(C)
11	2016 RNS Revenue Credits under Present Rates (Lines 6 + 7 + 8 - 9 - 10)	$ 216,750,485	To Line 2(B)

(4)

Line	Description	Amount	Source
12	RNS Revenue Credits under Present Rates	$ 216,750,485	Line 2(B)
13	Plus: Incremental Estimated PTF Revenue Requirements	3,192,000	Exhibit No. ES-222, Schedule 1, Page 1 of 1, Line 3(D)
14	Less: Impact on RNS Revenue Credits due to 50 basis points	1,906	Exhibit No. ES-222, Schedule 5, Page 3 of 5, Line 46, Col.C **Less** Exhibit No. ES-222, Schedule 2, Page 3 of 5, Line 46, Col.C
15	RNS Revenue Credits under Proposed Language *(Lines 6 + 7 - 8)*	$ 219,940,579	To Line 2(C)

(5)

Line	Description	Amount	Source
16	S&D Revenue Credits under Present Rates	$ 5,576,120	Line 3(B)
17	Incremental Estimated PTF Revenue Requirements	$ 26,000	Exhibit No. ES-223, Schedule 1, Page 1 of 1, Line 3(D)
18	S&D Revenue Credits under Changed Rates (Line 10 + 11)	$ 5,602,120	To Line 3(C)

Exhibit No. ES-225
Schedule 2

Schedule 21-NSTAR Revenue Requirements under the Present Rates

Eversource Energy Service Company

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-NSTAR Revenue Requirement Comparison Under Present Rates
Under Attachment D
For the Calendar Years 2016-2018

	(A)	(B)	(C)	
Line	**Description**	**Reference**	**Total NSTAR Electric**	
1	2014 Actual Schedule 21-NSTAR Revenue Requirement	Exhibit No. ES-225, Schedule 2, Page 2 of 5, Note (d)	$ 280,598,800	
2	Estimated 2015 Schedule 21-NSTAR Plant Additions	(1)	$ 196,000,000	
3	Carrying Charge Factor (CCF)	Exhibit No. ES-225, Schedule 2, Page 2 of 5, Note (c)	14.6504%	
4	2015 Incremental Estimated Schedule 21-NSTAR Revenue Requirement	Line 2 x 3	28,714,784	
5	2015 Incremental Estimated Schedule 21-NSTAR CWIP Rev. Req.	(1)	$ 1,366,439	
6	Total Estimated Schedule 21-NSTAR Revenue Requirement for 2015	Line 1 + 4 + 5	$ 310,680,023	
7	Estimated 2016 Schedule 21-NSTAR Plant Additions	(1)	$ 237,000,000	
8	Carrying Charge Factor (CCF)	Line 3	14.6504%	
9	2016 Incremental Estimated Schedule 21-NSTAR Revenue Requirement	Line 7 x 8	34,721,448	
10	Total Estimated Schedule 21-NSTAR Revenue Requirement for 2016	Line 6 + 9	$ 345,401,471	(2)

Notes:
(1) Based on Eversource's Forecast
(2) The revenue requirements calculations for the calendar year 2016 (including any forecast for 2016) are used as an estimate for the revenue requirements for 2017 and 2018, which are used to calculate the revenue impact of the proposed cost recovery

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
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Under Attachment D
For Costs in 2014
Sheet 1a

	(a)	(b)	(c)	(d)	(e)
Line	**Description**	**Section**	**Amount**	**Reference**	**Notes**
1	**Investment Base**	II.A.1			
2	Transmission Plant	II.A.1.a	$ 1,915,292,693	Sheet 3, Line 1, Col (f)	(a)
3	Transmission Related Intangible & General Plant	II.A.1.b	26,538,303	Sheet 3, Line 4, Col (f)	(a)
4	Transmission Plant Held for Future Use	II.A.1.c	13,571,504	Sheet 3, Line 5, Col (f)	(a)
5	Transmission Related Construction Work in Progress	II.A.1.d	45,961,764	Sheet 3, Line 6, Col (f)	(a)
6	Total Plant		2,001,364,264	Sum Lines 2 thru 5	
7	Trans Related Depreciation and Amortization Reserve	II.A.1.e	(462,609,062)	Sheet 3, Line 12, Col (f)	(a)
8	Transmission Related Accumulated Deferred Taxes	II.A.1.f	(367,674,233)	Sheet 3, Line 20, Col (f)	(a)
9	AFUDC Regulatory Liability	II.A.1.g	(4,435,570)	Sheet 3, Line 21, Col (f)	(a)
10	Total Net Plant		1,166,645,399	Sum Lines 6 thru 9	
11	Transmission Related Gain/Loss on Reacquired Debt	II.A.1.h	3,692,875	Sheet 3, Line 22, Col (f)	(a)
12	Other Trans Related Regulatory Assets/Liabilities	II.A.1.i	24,039,339	Sheet 3, Line 28, Col (f)	(b)
13	Transmission Prepayments	II.A.1.j	56,057,444	Sheet 3, Line 29, Col (f)	(a)
14	Transmission Materials & Supplies	II.A.1.k	28,541,503	Sheet 3, Line 30, Col (f)	(a)
15	Transmission Related Cash Working Capital	II.A.1.l	6,067,021	Sheet 3, Line 35, Col (f)	(b)
16	**Total Investment Base**		$ 1,285,043,581	Sum Lines 10 thru 15	(b)
17	**Revenue Requirement**				
18	Investment Return and Income Taxes	II.A.2	$ 153,380,232	Sheet 2a, Line 39, Col (c)	(b)
19	Transmission Depreciation and Amortization Expense	II.B	42,559,825	Sheet 4 , Line 7, Col (f)	(a)
20	Amortization of Gain/Loss on Reacquired Debt	II.C	286,851	Sheet 4 , Line 8, Col (f)	(a)
21	Transmission Related Amort. of Investment Tax Credits	II.D	(376,034)	Sheet 4 , Line 9, Col (f)	(a)
22	Transmission Related Municipal Tax Expense	II.E	34,612,127	Sheet 4 , Line 10, Col (f)	(a)
23	Transmission Related Payroll Tax Expense	II.F	1,599,627	Sheet 4 , Line 11, Col (f)	(a)
24	Transmission Operation & Maintenance Expense	II.G	25,099,553	Sheet 4 , Line 30, Col (f)	(a)
25	Transmission Related Administrative and General Expense	II.H	19,624,754	Sheet 4 , Line 42, Col (f)	(b)
26	Transmission Related Integrated Facilities Charges	II.I	-	Sheet 5 - Page 1 of 2, Line 6, Col (d)	(a)
27	Transmission Support Revenues	II.J	(4,509,913)	Sheet 5 - Page 1 of 2, Line 45, Col (d)	(a)
28	Transmission Support Expense	II.K	3,811,865	Sheet 5 - Page 1 of 2, Line 57, Col (d)	(a)
29	Transmission Related Expense from Generators	II.L	-	Sheet 5 - Page 1 of 2, Line 60, Col (d)	(a)
30	Transmission Rents Received from Electric Property	II.M	(3,129,907)	Sheet 5 - Page 2 of 2, Line 66, Col (d)	(a)
31	Short-Term and Non-Firm P-T-P Service Revenues	II.N	-	Sheet 5 - Page 2 of 2, Line 69, Col (d)	(a)
32	Regional Network Services (RNS) Revenues	II.O	(173,183,026)	Sheet 5a, Line 6, Col (d)	(a)
33	Through or Out Revenues	II.P	(275,884)	Sheet 5 - Page 2 of 2, Line 78, Col (d)	(a)
34	ISO-NE Scheduling and Dispatch Revenues	II.Q	(5,576,120)	Sheet 5 - Page 2 of 2, Line 82, Col (d)	(a)
35	**Total LNS Revenue Requirement**		$ 93,923,950	Sum Lines 18 thru 34	(b)
36	Wholesale LNS Revenues Received:				
37	MBTA		(904,082)	Sheet 5 - Page 1 of 2, Line 22, Col (c)	(b)
38	Concord		(140,908)	Sheet 5 - Page 1 of 2, Line 23, Col (c)	(b)
39	Massachusetts Port Authority (MASSPORT)		(620,561)	Sheet 5 - Page 1 of 2, Line 24, Col (c)	(b)
40	Nantucket-LNS		(296,522)	Sheet 5 - Page 1 of 2, Line 25, Col (c)	(b)
41	Covanta-SEMass		(133,071)	Sheet 5 - Page 1 of 2, Line 27, Col (c)	(b)
42	Total Wholesale LNS Revenue		$ (2,095,144)	Sum Lines 37 thru 41	(b)
					(b)
43	**Total Retail LNS Revenue Requirement**		**$ 91,828,806**	Line 35 - Line 42	(b)
					(b)
					(b)
44	Average 12 CP				(b)
45	Sum of Monthly Peaks (kW)		48,920,000	FF1 Page 400.17(b) *1000	(b)
46	Average Peak		4,076,667	Line 45 / 12	(b)
					(b)
47	Annual Rate per kW		$ 23.0394	Line 35 / Line 46	(b)
48	Monthly Rate per kW		$ 1.9200	Line 47 / 12	(b)
49	Weekly Rate per kW		$ 0.4431	Line 47 / 52	(b)
50	Daily Rate per kW		$ 0.0631	Line 47 / 365	(b)
51	Hourly Rate per kW		$ 0.0026	Line 47 / 8760	(b)

This reflects an ROE of 10.57% per FERC Order in Docket No. EL11-66 dated October 16, 2014.

Notes:

(a) Source of information is the NSTAR Annual Informational Filing submitted to FERC on August 14, 2015 in Docket No. ER07-549 and ER09-1243.

(b) Source of information is the NSTAR Annual Informational Filing submitted to FERC on August 14, 2015 in Docket No. ER07-549 and ER09-1243. Provided this support because these balances will be revised under the changed rates.

(c) Carrying Charge Factor (Sum Lines 18-25 and 28 / Line 2) 14.6504%

(d) Total LNS Revenue Requirements (Sum Lines 18 - 25 and Line 28) $ 280,598,800

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-NSTAR Revenue Requirement Comparison Under Present Rates
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Sheet 2a

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Line	Description	Tariff Section	Balance	Capitalization Ratio	Cost	Weighted Cost	Equity Cost	Reference	Notes
1	**Weighted Cost of Capital**	II.A.2.a							
2	Long Term Debt	II.A.2.a.i	$ 1,792,712,148	41.74%	4.19%	1.75%		FF1 Page 112.24(c)	(a)
3	Preferred Stock	II.A.2.a.ii	43,000,000	1.00%	4.56%	0.05%	0.05%	FF1 Page 112.3(c)	(a)
4	Common Equity	II.A.2.a.iii	2,459,452,736	57.26%	10.57%	6.05%	6.05%	FF1 Page 112.16(c) - Line 3(c)	(a)
5	Total		$ 4,295,164,884			7.85%	6.10%	Sum Lines 2 thru 4	(a)

ROE per ISO New England Inc. Transmission, Markets and Services Tariff, Schedule 21-NSTAR Attachment D II.A.2.(a)(iii), page 60
http://www.iso-ne.com/regulatory/tariff/sect_2/sch21/sch_21_nstar.pdf

Line	Description	Tariff Section	Balance	Reference	Notes
6	**Investment Return**	II.A.2			
7	Total Investment Base		$ 1,285,043,581	Sheet 1, Line 16, Col (c)	(b)
8	Weighted Cost of Capital		7.85%	Line 5, Col (f)	(a)
9	Total Return on Investment		**$ 100,875,921**	Line 7 * Line 8	(b)
10	**Federal Income Tax**	II.A.2.b			
11	A = Equity Cost		6.10%	Line 5, Col (g)	(a)
12	B = Transmission Amortization of ITC		$ (376,034)	Sheet 1, Line 21, Col (c)	(a)
13	C = Equity AFUDC		91,676	FF1 Page 336.7(b) Footnote + FF1 Page 336.10(b) Footnote	(a)
14	Total B + C		(284,358)	Line 12 + Line 13	(a)
15	D = Investment Base		1,285,043,581	Line 7	(b)
16	(B + C) / D		-0.0221%	Line 14 / Line 15	(b)
17	(A + [(C + B) / D]		6.0779%	Line 11 + Line 16	(b)
18	FT = Federal Income Tax Rate		35.00%	Federal corporate tax rate	(a)
19	1 - FT		65.00%	1 - Line 18	(a)
20	Federal Tax Factor		3.2727%	Line 17 * Line 18 / Line 19	(a)
21	Total Federal Income Taxes		**$ 42,055,621**	Line 15 * Line 20	(b)
22	**State Income Tax**	II.A.2.c			
23	A = Equity Cost		6.10%	Line 5, Col (g)	(a)
24	B = Transmission Amortization of ITC		$ (376,034)	Sheet 1, Line 21, Col (c)	(a)
25	C = Equity AFUDC		91,676	FF1 Page 336.7(b) Footnote + FF1 Page 336.10(b) Footnote	(a)
26	Total B + C		(284,358)	Line 24 + Line 25	(a)
27	D = Investment Base		1,285,043,581	Line 7	(b)
28	(B + C) / D		-0.0221%	Line 26 / Line 27	(b)
29	(A + [(C + B) / D]		6.0779%	Line 23 + Line 28	(b)
30	ST = State Income Tax Rate		8.00%	Massachusetts corporate tax rate	(a)
31	1 - ST		92.00%	1 - Line 30	(a)
32	Federal Tax Factor		3.2727%	Line 20	(a)
33	State Tax Factor		0.8131%	(Line 29 + Line 32) * Line 30 / Line 31	(a)
34	Total State Income Taxes		**$ 10,448,689**	Line 27 * Line 33	(b)
35	**Investment Return and Income Taxes**	II.A.2			
36	Return on Investment		$ 100,875,921	Line 9	(b)
37	Federal Income Taxes		42,055,621	Line 21	(b)
38	State Income Taxes		10,448,689	Line 34	(b)
39	**Total Return and Income Taxes**		**$ 153,380,232**	Sum Lines 36 thru 38	(b)

Notes:
(a) Source of information is the NSTAR Annual Informational Filing submitted to FERC on August 14, 2015 in Docket No. ER07-549 and ER09-1243.
(b) Source of information is the NSTAR Annual Informational Filing submitted to FERC on August 14, 2015 in Docket No. ER07-549 and ER09-1243. Provided this support because these balances will be revised under the changed rates.

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-NSTAR Revenue Requirement Comparison Under Present Rates
Under Attachment D
For Costs in 2014
Sheet 3

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		Tariff		Allocations				
Line	Description	Section	Total	Allocator	Factor	LNS Amount	Reference	Notes
1	**Transmission Plant**	II.A.1.a	$ 1,915,292,693	Direct	100.0000%	$ 1,915,292,693	FF1 Page 207.58(g)	(a)
2	General Plant		186,941,660	W&S	12.8871%	24,091,359	FF1 Page 207.99(g)	(a)
3	Intangible Plant		18,987,542	W&S	12.8871%	2,446,944	FF1 Page 205.5(g)	(a)
4	**Total Intangible & General Plant**	II.A.1.b				26,538,303	Sum Lines 2 thru 3	
5	**Transmission Plant Held for Future Use**	II.A.1.c	13,571,504	Direct	100.0000%	13,571,504	FF1 Page 214.14(d) + FF1 Page 214.15(d) + FF1 Page 214.16(d) + FF1 Page 214.17(d) + FF1 Page 214.18(d)	(a)
6	**Transmission Related CWIP - Note 1**	II.A.1.d	91,923,527	CWIP	50.0000%	45,961,764	FF1 Page 216, lines 32(b), 34(b) thru 42(b), and Page 216.1, lines 1(b), 2(b), 5(b), 6(b), 10(b) thru 12(b) 14(part)(b) Trans only	(a)
7	**Transmission Related Dep & Amort Reserve**	II.A.1.e						
8	Transmission Accumulated Depreciation		(453,776,651)	Direct	100.0000%	(453,776,651)	FF1 Page 219.25(b)	(a)
9	General Plant Accumulated Depreciation		(52,490,917)	W&S	12.8871%	(6,764,557)	FF1 Page 219.28(b)	(a)
10	General Plant Accumulated Amortization		(6,245,258)	W&S	12.8871%	(804,833)	FF1 Page 200.21(c) Footnote	(a)
11	Intangible Plant Accumulated Amortization		(9,800,663)	W&S	12.8871%	(1,263,021)	FF1 Page 200.21(c) Footnote	(a)
12	Total Transmission Related Depreciation Reserve		(522,313,489)			(462,609,062)	Sum Lines 8 thru 11	
13	**Transmission Accumulated Deferred Taxes**	II.A.1.f						
14	Accumulated Deferred Taxes (190)		63,896,752		13.6034%	8,692,119	Sheet 8, Line 12, col (d)	(a)
15	Accumulated Deferred Income Taxes (281)		-			-	FF1 Page 113.62(c)	(a)
16	Accumulated Deferred Taxes - Property (282)		(1,143,462,163)				FF1 Page 275.9(k)	(a)
17	Less Transition Property		-				FF1 Page 275.4(k)	(a)
18	Net Acc. Def. Income Taxes - Other Property (282)		(1,143,462,163)	Plant	28.7026%	(328,203,371)	Sum Lines 16 thru 17	
19	Accumulated Deferred Income Taxes - Other (283)		(506,588,448)		9.5073%	(48,162,981)	Sheet 8, Line 27, col (d)	(a)
20	Total					(367,674,233)	Line 14 + Line 15 + Line 18 + Line 19	
21	**AFUDC Regulatory Liability**	II.A.1.g	(4,435,570)	Direct	100.0000%	(4,435,570)	FF1 Page 278.3(f)	(a)
22	**Gain/Loss on Reacquired Debt**	II.A.1.h	12,865,994	Plant	28.7026%	3,692,875	FF1 Page 111.81(c) + FF1 Page 113.61(c)	(a) (a)
23	**Other Regulatory Assets**	II.A.1.i						
24	FAS 106 (182.3 & 254)		-	W&S	12.8871%	-	FF1 Page 232	(a)
25	ASC 740 (182.3 - FAS 109)		87,768,732				FF1 Page 232.29(f)	(a)
26	Less ASC 740 Liability (254 - FAS 109)		(4,015,556)				FF1 Page 278.1(f)	(a)
27	Net ASC 740 (182.3 & 254 - FAS 109)		83,753,176	Plant	28.7026%	24,039,339	Sum Lines 25 thru 26	(a)
28	Total Other Regulatory Assets		83,753,176			24,039,339	Line 24 + line 27	(b)
29	**Prepayments**	II.A.1.j	434,988,820	W&S	12.8871%	56,057,444	FF1 Page 111.57(c) + FF1 Page 232.1.2(f) +Page 232.1.3(f)	(a)
30	**Transmission Materials & Supplies**	II.A.1.k	28,541,503	Direct	100.0000%	28,541,503	FF1 Page 227.8(c) + FF1 Page 227.5(c) Footnote	(a)
31	**Cash Working Capital**	II.A.1.l						
32	Operation & Maintenance Expense		25,099,553	WC	12.5000%	3,137,444	Sheet 1a, Line 24, col (c)	(a)
33	Administrative & General Expense		19,624,754	WC	12.5000%	2,453,094	Sheet 1a, Line 25, col (c)	(b)
34	Transmission Support Expenses		3,811,865	WC	12.5000%	476,483	Sheet 1a, Line 28, col (c)	(a)
35	Total Cash Working Capital		48,536,172			6,067,021	Sum Lines 32 thru 34	(b)

Line	Description	Allocation Factor	Reference	Notes
36				
37	Direct Allocation (Direct)	100.0000%		(a)
38	Wages & Salary (W&S)	12.8871%	Sheet 6, Line 6(c)	(a)
39	Plant Allocation (Plant)	28.7026%	Sheet 6, Line 14(c)	(a)
40	Construction Work in Progress Allocation (CWIP)	50.0000%	Sheet 6, Line 15(c)	(a)
41	Cash Working Capital (WC)	12.50%	Tariff Section II.A.1.l	(a)

42 **Note 1 -** Internal Records identify CWIP projects for rate base, as noted in the Exhibit "2014 Construction Work in Progress" included in this filing.

Notes:
(a) Source of information is the NSTAR Annual Informational Filing submitted to FERC on August 14, 2015 in Docket No. ER07-549 and ER09-1243.
(b) Source of information is the NSTAR Annual Informational Filing submitted to FERC on August 14, 2015 in Docket No. ER07-549 and ER09-1243. Provided this support because these balances will be revised under the changed rates.

NSTAR Electric Company
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Estimated Schedule 21-NSTAR Revenue Requirement Comparison Under Present Rates
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Sheet 4

Line	(a) Description	(b) Tariff Section	(c) Total	(d) Allocator	(e) Factor	(f) Allocations LNS Amount	(g) Reference	Notes
1	**Transmission Depreciation and Amortization Expense**	II.B						
2	Transmission Depreciation	II.B.i	$ 41,001,613	Direct	100.0000%	$ 41,001,613	FF1 Page 336.7(f)	(a)
3	General Plant Depreciation and Amortization	II.B.ii	8,991,113	W&S	12.8871%	1,158,694	FF1 Page 336.10(f)	(a)
4	Amortization of Transmission Related Intangible Plant		4,111,761	W&S	12.8871%	529,887	FF1 Page 336.1(f)	(a)
5	Amortization of AFUDC Regulatory Credit		(130,369)			(130,369)	FF1 Page 114.13(c)	(a)
6	Net Amortization of Transmission Related Intangible Plant		$ 3,981,392			$ 399,518	Sum Lines 4 and 5	(a)
7	Total Transmission Depreciation and Amortization Expense		$ 53,974,118			$ 42,559,825	Sum Lines 2, 3 and 6	(a)
8	**Amortization of Gain/Loss on Reacquired Debt**	II.C	$ 999,391	Plant	28.7026%	$ 286,851	FF1 Page 117.64(c) + FF1 Page 117.66(c)	(a)
9	**Transmission Related Amortization of ITC**	II.D	$ (1,310,106)	Plant	28.7026%	$ (376,034)	FF1 Page 114.19(c)	(a)
10	**Transmission Related Municipal Tax Expense**	II.E	$ 120,588,821	Plant	28.7026%	$ 34,612,127	FF1 Page 263.5(i)	(a)
11	**Transmission Related Payroll Tax Expense**	II.F	$ 12,412,619	W&S	12.8871%	$ 1,599,627	FF1 Page 263.10(i)	(a)
12	**Transmission Operation and Maintenance Expense**	II.G						
13	Operation Supervision & Engineering (560)		$ 5,674,265	Direct	100.0000%	5,674,265	FF1 Page 321.83(b)	(a)
14			-	Internal Costs		-	FF1 Page 321.84(b)	(a)
15	Load Dispatch - Reliability (561.1)		1,389,220	Internal Costs		1,389,220	FF1 Page 321.85(b)	(a)
16	Load Dispatch-Monitor and Operate Transmission System (561.2)		1,311,222	Internal Costs		1,311,222	FF1 Page 321.86(b)	(a)
17	Load Dispatch-Transmission Service and Scheduling (561.3)		570,681	Internal Costs		570,681	FF1 Page 321.87(b)	(a)
18	Scheduling, System Control and Dispatch Services (561.4)		12,155,295	External Costs		-	FF1 Page 321.88(b)	(a)
19	Reliability, Planning and Standards Development (561.5)		273,226	Internal Costs		21,719	FF1 Page 321.89(b)	(a)
20	Transmission Service Studies (561.6)		106	Internal Costs		106	FF1 Page 321.90(b)	(a)
21	Generation Interconnection Studies (561.7)		-	Internal Costs		-	FF1 Page 321.91(b)	(a)
22	Reliability, Planning and Standards Development Services (561.8)		53,935	External Costs		-	FF1 Page 321.92(b)	(a)
23	Station Expenses (562)		2,729,963	Direct	100.0000%	2,729,963	FF1 Page 321.93(b)	(a)
24	Overhead Lines Expenses (563)		4,327,839	Direct	100.0000%	4,327,839	FF1 Page 321.94(b)	(a)
25	Underground Lines Expenses (564)		636,122	Direct	100.0000%	636,122	FF1 Page 321.95(b)	(a)
26	Miscellaneous Transmission Expenses (566)		496,506	Direct	100.0000%	496,506	FF1 Page 321.97(b)	(a)
27	Rents (567)		14,755	Direct	100.0000%	14,755	Sheet 5 - Page 1 of 2, Line 3, col (d)	(a)
28	Transmission Maintenance (568 - 573)		7,927,155	Direct	100.0000%	7,927,155	FF1 Page 321.111(b)	(a)
29	Regional Market Expense (575-576)		424,648	External Costs	0.0000%	-	FF1 Page 322.131(b)	(a)
30	Total Transmission O&M Expense		$ 37,984,938			$ 25,099,553	Sum Lines 13 thru 29	(a)
31	**Transmission Related A&G Expenses**	II.H						
32	Administrative and General Expenses	I.B	$ 145,329,829				FF1 Page 323.197(b)	(a)
33	Property Insurance (924)		(926,016)				FF1 Page 323.185(b)	(a)
34	Employee Pensions and Benefits (926)		(51,124,252)				FF1 Page 323.187(b)	(a)
35	Regulatory Commission Expenses (928)		(9,560,209)				FF1 Page 323.189(b)	(a)
36	General Advertising Expenses (930.1)		(32,018)				FF1 Page 323.191(b)	(a)
37	Miscellaneous General Expenses (930.2) - **Note 2**		(52,118)				FF1 Page 232.2.14(e)	(a)
38	Sub-Total	II.H.1	83,635,216	W&S	12.8871%	10,778,154	Sum Lines 32 thru 37	(b)
39	Property Insurance (924)	II.H.2	926,016	Plant	28.7026%	265,791	Line 33	(a)
40	Employee Pensions and Benefits (926) - **Note 1**	II.H.1	51,124,252	W&S	12.8871%	6,588,433	Line 34	(a)
41	Regulatory Commission Expenses (928)	II.H.3	9,560,209	Footnote	20.8403%	1,992,376	Line 48	(a)
42	Total Transmission Related A&G Expenses		$ 145,245,693			$ 19,624,754	Sum Lines 38 thru 41	(b)
43	Regulatory Commission Expenses (928)	II.H.3						(a)
44	Assessment Charged by the MA DPU		$ 6,712,589		0.0000%	$ -	FF1 Page 350.2(d)	(a)
45	Proportionate share of expenses of FERC Assessment Order No. 472		1,992,376	Direct	100.0000%	1,992,376	FF1 Page 350.6(d)	(a)
46	Legal Fees - Distribution		787,573		0.0000%	-	FF1 Page 350.8(d)	(a)
47	Minor items - Distribution		67,671		0.0000%	-	FF1 Page 350.10(d)	(a)
48	Total Regulatory Commission Expenses	II.H.3	$ 9,560,209		20.8403%	$ 1,992,376	Sum Lines 44 thru 47	(a)

Line	Description	Allocation Factor	Reference	Notes
49				
50	Direct Allocation (Direct)	100.0000%		(a)
51	Wages & Salaries Allocation (W&S)	12.8871%	Sheet 6, Line 6(c)	(a)
52	Plant Allocation (Plant)	28.7026%	Sheet 6, Line 14(c)	(a)

53 **Note 1**

54 Included in the Employee Pension and Benefits Expenses are costs related to Post Retirement Benefits other than Pension (PBOP). PBOP costs are determined by an independent actuary

55 as required by ASC 715. The PBOP expense included in Account 926 for 2014 was ($5,000,000) as compared to $4,600,000 in 2013; as shown on the FF1, page 323, footnote.

56 Applying the labor allocator to the total PBOP expense results in $(251,041) of PBOP expense being recovered through the LNS Tariff in 2014, as compared to $249,762 in the prior year.

Line		2014	2013		Notes
57	PBOP	$ (5,000,000)	$ 4,600,000	Page 323 line 187 footnote	(a)
58	Capitalized PBOP & Other impact adjustment	3,052,000	(1,866,000)	**Note 3**	(a)
59	Net PBOP in account 926	$ (1,948,000)	$ 2,734,000	Line 57 + Line 58	(a)
60	Wages & Salaries Allocation (W&S)	12.8871%	9.1354%	Sheet 6	(a)
61	LNS portion of PBOP	$ (251,041)	$ 249,762	Line 59 x Line 60	(a)

62 **Note 2 -** NSTAR Green Program costs are excludable for Transmission billing purposes. Reflects actual information per Eversource's

63 **Note 3** - Reflects actual information per Eversource's accounting records. ;

Notes:

(a) Source of information is the NSTAR Annual Informational Filing submitted to FERC on August 14, 2015 in Docket No. ER07-549 and ER09-1243.

(b) Source of information is the NSTAR Annual Informational Filing submitted to FERC on August 14, 2015 in Docket No. ER07-549 and ER09-1243. Provided this support because these balances will be revised under the changed rates.

Exhibit No. ES-225
Schedule 3

Schedule 21-NSTAR Revenue Requirements under the Changed Rates for 2016

Eversource Energy Service Company

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-NSTAR Revenue Requirement Comparison Under Changed Rates
Under Attachment D
For the Calendar year 2016

	(A)	(B)	(C)
Line	**Description**	**Reference**	**Total NSTAR Electric**
1	2014 Actual Schedule 21-NSTAR Revenue Requirement	Exhibit No. ES-225, Schedule 3, Page 2 of 5, Note (c)	$ 285,376,689
2	Estimated 2015 Schedule 21-NSTAR Plant Additions	(1)	$ 196,000,000
3	Carrying Charge Factor (CCF)	Exhibit No. ES-225, Schedule 2, Page 2 of 5, Note (c)	14.6504%
4	2015 Incremental Estimated Schedule 21-NSTAR Revenue Requirement	Line 2 x 3	28,714,784
5	2015 Incremental Estimated Schedule 21-NSTAR CWIP Revenue Requirements	(1)	$ 1,366,439
6	Total Estimated Schedule 21-NSTAR Revenue Requirement for 2015	Line 1 + 4 + 5	$ 315,457,912
7	Estimated 2016 Schedule 21-NSTAR Plant Additions	(1)	$ 237,000,000
8	Carrying Charge Factor (CCF)	Line 3	14.65%
9	2016 Incremental Estimated Schedule 21-NSTAR Revenue Requirement	Line 7 x 8	34,721,448
10	Total Estimated Schedule 21-NSTAR Revenue Requirement for 2016	Line 6 + 9 + 10	$ 350,179,360

Notes:
(1) Based on Eversource's Forecast

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-NSTAR Revenue Requirement Comparison Under Changed Rates
Under Attachment D
For Costs in 2014
Sheet 1a

	(a)	(b)		(c)	(d)	(e)
Line	**Description**	**Section**		**Amount**	**Reference**	**Notes**
1	**Investment Base**	II.A.1				
2	Transmission Plant	II.A.1.a	$	1,915,292,693	Sheet 3, Line 1, Col (f)	(a)
3	Transmission Related Intangible & General Plant	II.A.1.b		26,538,303	Sheet 3, Line 4, Col (f)	(a)
4	Transmission Plant Held for Future Use	II.A.1.c		13,571,504	Sheet 3, Line 5, Col (f)	(a)
5	Transmission Related Construction Work in Progress	II.A.1.d		45,961,764	Sheet 3, Line 6, Col (f)	(a)
6	Total Plant			2,001,364,264	Sum Lines 2 thru 5	
7	Trans Related Depreciation and Amortization Reserve	II.A.1.e		(462,609,062)	Sheet 3, Line 12, Col (f)	(a)
8	Transmission Related Accumulated Deferred Taxes	II.A.1.f		(367,674,233)	Sheet 3, Line 20, Col (f)	(a)
9	AFUDC Regulatory Liability	II.A.1.g		(4,435,570)	Sheet 3, Line 21, Col (f)	(a)
10	Total Net Plant			1,166,645,399	Sum Lines 6 thru 9	
11	Transmission Related Gain/Loss on Reacquired Debt	II.A.1.h		3,692,875	Sheet 3, Line 22, Col (f)	(a)
12	Other Trans Related Regulatory Assets/Liabilities	II.A.1.i		31,659,729	Sheet 3, Line 29, Col (f)	(b)
13	Transmission Prepayments	II.A.1.j		56,057,444	Sheet 3, Line 30, Col (f)	(a)
14	Transmission Materials & Supplies	II.A.1.k		28,541,503	Sheet 3, Line 31, Col (f)	(a)
15	Transmission Related Cash Working Capital	II.A.1.l		6,543,296	Sheet 3, Line 36, Col (f)	(b)
16	**Total Investment Base**		$	1,293,140,246	Sum Lines 10 thru 15	(b)
17	**Revenue Requirement**					
18	Investment Return and Income Taxes	II.A.2	$	154,347,926	Sheet 2a, Line 39, Col (c)	(b)
19	Transmission Depreciation and Amortization Expense	II.B		42,559,825	Sheet 4 , Line 7, Col (f)	(a)
20	Amortization of Gain/Loss on Reacquired Debt	II.C		286,851	Sheet 4 , Line 8, Col (f)	(a)
21	Transmission Related Amort. of Investment Tax Credits	II.D		(376,034)	Sheet 4 , Line 9, Col (f)	(a)
22	Transmission Related Municipal Tax Expense	II.E		34,612,127	Sheet 4 , Line 10, Col (f)	(a)
23	Transmission Related Payroll Tax Expense	II.F		1,599,627	Sheet 4 , Line 11, Col (f)	(a)
24	Transmission Operation & Maintenance Expense	II.G		25,099,553	Sheet 4 , Line 30, Col (f)	(a)
25	Transmission Related Administrative and General Expense	II.H		23,434,949	Sheet 4 , Line 44, Col (f)	(b)
26	Transmission Related Integrated Facilities Charges	II.I		-	Sheet 5 - Page 1 of 2, Line 6, Col (d)	(a)
27	Transmission Support Revenues	II.J		(4,509,913)	Sheet 5 - Page 1 of 2, Line 45, Col (d)	(a)
28	Transmission Support Expense	II.K		3,811,865	Sheet 5 - Page 1 of 2, Line 57, Col (d)	(a)
29	Transmission Related Expense from Generators	II.L		-	Sheet 5 - Page 1 of 2, Line 60, Col (d)	(a)
30	Transmission Rents Received from Electric Property	II.M		(3,129,907)	Sheet 5 - Page 2 of 2, Line 66, Col (d)	(a)
31	Short-Term and Non-Firm P-T-P Service Revenues	II.N		-	Sheet 5 - Page 2 of 2, Line 69, Col (d)	(a)
32	Regional Network Services (RNS) Revenues	II.O		(173,183,026)	Sheet 5a, Line 6, Col (d)	(a)
33	Through or Out Revenues	II.P		(275,884)	Sheet 5 - Page 2 of 2, Line 78, Col (d)	(a)
34	ISO-NE Scheduling and Dispatch Revenues	II.Q		(5,576,120)	Sheet 5 - Page 2 of 2, Line 82, Col (d)	(a)
35	**Total LNS Revenue Requirement**		$	98,701,839	Sum Lines 18 thru 34	(b)
36	Wholesale LNS Revenues Received:					
37	MBTA			(904,082)	Sheet 5 - Page 1 of 2, Line 22, Col (c)	(b)
38	Concord			(140,908)	Sheet 5 - Page 1 of 2, Line 23, Col (c)	(b)
39	Massachusetts Port Authority (MASSPORT)			(620,561)	Sheet 5 - Page 1 of 2, Line 24, Col (c)	(b)
40	Nantucket-LNS			(296,522)	Sheet 5 - Page 1 of 2, Line 25, Col (c)	(b)
41	Covanta-SEMass			(133,071)	Sheet 5 - Page 1 of 2, Line 27, Col (c)	(b)
42	Total Wholesale LNS Revenue		$	(2,095,144)	Sum Lines 37 thru 41	(b)
						(b)
43	**Total Retail LNS Revenue Requirement**		**$**	**96,606,695**	Line 35 - Line 42	(b)
						(b)
						(b)
44	Average 12 CP					(b)
45	Sum of Monthly Peaks (kW)			48,920,000	FF1 Page 400.17(b) *1000	(b)
46	Average Peak			4,076,667	Line 45 / 12	(b)
						(b)
47	Annual Rate per kW		$	24.2114	Line 35 / Line 46	(b)
48	Monthly Rate per kW		$	2.0176	Line 47 / 12	(b)
49	Weekly Rate per kW		$	0.4656	Line 47 / 52	(b)
50	Daily Rate per kW		$	0.0663	Line 47 / 365	(b)
51	Hourly Rate per kW		$	0.0028	Line 47 / 8760	(b)

This reflects an ROE of 10.57% per FERC Order in Docket No. EL11-66 dated October 16, 2014.

Notes:

(a) Source of information is the NSTAR Annual Informational Filing submitted to FERC on August 14, 2015 in Docket No. ER07-549 and ER09-1243.
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset
(c) Total LNS Revenue Requirements (Sum Lines 18 - 25 and Line 28) $ 285,376,689

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-NSTAR Revenue Requirement Comparison Under Changed Rates
Under Attachment D
For Costs in 2014
Sheet 2a

Line	(a) Description	(b) Tariff Section	(c) Balance	(d) Capitalization Ratio	(e) Cost	(f) Weighted Cost	(g) Equity Cost	(h) Reference	(i) Notes
1	**Weighted Cost of Capital**	II.A.2.a							
2	Long Term Debt	II.A.2.a.i	$ 1,792,712,148	41.74%	4.19%	1.75%		FF1 Page 112.24(c)	(a)
3	Preferred Stock	II.A.2.a.ii	43,000,000	1.00%	4.56%	0.05%	0.05%	FF1 Page 112.3(c)	(a)
4	Common Equity	II.A.2.a.iii	2,459,452,736	57.26%	10.57%	6.05%	6.05%	FF1 Page 112.16(c) - Line 3(c)	(a)
5	Total		$ 4,295,164,884			7.85%	6.10%	Sum Lines 2 thru 4	(a)

ROE per ISO New England Inc. Transmission, Markets and Services Tariff, Schedule 21-NSTAR Attachment D II.A.2.(a)(iii), page 60
http://www.iso-ne.com/regulatory/tariff/sect_2/sch21/sch_21_nstar.pdf

Line	Description	Tariff Section	Balance	Reference	Notes
6	**Investment Return**	II.A.2			
7	Total Investment Base		$ 1,293,140,246	Sheet 1, Line 16, Col (c)	(b)
8	Weighted Cost of Capital		7.85%	Line 5, Col (f)	(a)
9	Total Return on Investment		**$ 101,511,509**	Line 7 * Line 8	(b)
10	**Federal Income Tax**	II.A.2.b			
11	A = Equity Cost		6.10%	Line 5, Col (g)	(a)
12	B = Transmission Amortization of ITC		$ (376,034)	Sheet 1, Line 21, Col (c)	(a)
13	C = Equity AFUDC		91,676	FF1 Page 336.7(b) Footnote + FF1 Page 336.10(b) Footnote	(a)
14	Total B + C		(284,358)	Line 12 + Line 13	(a)
15	D = Investment Base		1,293,140,246	Line 7	(b)
16	(B + C) / D		-0.0220%	Line 14 / Line 15	(b)
17	(A + [(C + B) / D]		6.0780%	Line 11 + Line 16	(b)
18	FT = Federal Income Tax Rate		35.00%	Federal corporate tax rate	(a)
19	1 - FT		65.00%	1 - Line 18	(a)
20	Federal Tax Factor		3.2728%	Line 17 * Line 18 / Line 19	(a)
21	Total Federal Income Taxes		**$ 42,321,894**	Line 15 * Line 20	(b)
22	**State Income Tax**	II.A.2.c			
23	A = Equity Cost		6.10%	Line 5, Col (g)	(a)
24	B = Transmission Amortization of ITC		$ (376,034)	Sheet 1, Line 21, Col (c)	(a)
25	C = Equity AFUDC		91,676	FF1 Page 336.7(b) Footnote + FF1 Page 336.10(b) Footnote	(a)
26	Total B + C		(284,358)	Line 24 + Line 25	(a)
27	D = Investment Base		1,293,140,246	Line 7	(b)
28	(B + C) / D		-0.0220%	Line 26 / Line 27	(b)
29	(A + [(C + B) / D]		6.0780%	Line 23 + Line 28	(b)
30	ST = State Income Tax Rate		8.00%	Massachusetts corporate tax rate	(a)
31	1 - ST		92.00%	1 - Line 30	(a)
32	Federal Tax Factor		3.2728%	Line 20	(a)
33	State Tax Factor		0.8131%	(Line 29 + Line 32) * Line 30 / Line 31	(a)
34	Total State Income Taxes		**$ 10,514,523**	Line 27 * Line 33	(b)
35	**Investment Return and Income Taxes**	II.A.2			
36	Return on Investment		$ 101,511,509	Line 9	(b)
37	Federal Income Taxes		42,321,894	Line 21	(b)
38	State Income Taxes		10,514,523	Line 34	(b)
39	**Total Return and Income Taxes**		**$ 154,347,926**	Sum Lines 36 thru 38	(b)

Notes:
(a) Source of information is the NSTAR Annual Informational Filing submitted to FERC on August 14, 2015 in Docket No. ER07-549 and ER09-1243.
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-NSTAR Revenue Requirement Comparison Under Changed Rates
Under Attachment D
For Costs in 2014
Sheet 3

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		Tariff		Allocations				
Line	Description	Section	Total	Allocator	Factor	LNS Amount	Reference	Notes
1	**Transmission Plant**	II.A.1.a	$ 1,915,292,693	Direct	100.0000%	$ 1,915,292,693	FF1 Page 207.58(g)	(a)
2	General Plant		186,941,660	W&S	12.8871%	24,091,359	FF1 Page 207.99(g)	(a)
3	Intangible Plant		18,987,542	W&S	12.8871%	2,446,944	FF1 Page 205.5(g)	(a)
4	**Total Intangible & General Plant**	II.A.1.b				26,538,303	Sum Lines 2 thru 3	
5	**Transmission Plant Held for Future Use**	II.A.1.c	13,571,504	Direct	100.0000%	13,571,504	FF1 Page 214.14(d) + FF1 Page 214.15(d) + FF1 Page 214.16(d) + FF1 Page 214.17(d) + FF1 Page 214.18(d)	(a)
6	**Transmission Related CWIP - Note 1**	II.A.1.d	91,923,527	CWIP	50.0000%	45,961,764	FF1 Page 216, lines 32(b), 34(b) thru 42(b), and Page 216.1, lines 1(b), 2(b), 5(b), 6(b), 10(b) thru 12(b) 14(part)(b) Trans only	(a)
7	**Transmission Related Dep & Amort Reserve**	II.A.1.e						
8	Transmission Accumulated Depreciation		(453,776,651)	Direct	100.0000%	(453,776,651)	FF1 Page 219.25(b)	(a)
9	General Plant Accumulated Depreciation		(52,490,917)	W&S	12.8871%	(6,764,557)	FF1 Page 219.28(b)	(a)
10	General Plant Accumulated Amortization		(6,245,258)	W&S	12.8871%	(804,833)	FF1 Page 200.21(c) Footnote	(a)
11	Intangible Plant Accumulated Amortization		(9,800,663)	W&S	12.8871%	(1,263,021)	FF1 Page 200.21(c) Footnote	(a)
12	Total Transmission Related Depreciation Reserve		(522,313,489)			(462,609,062)	Sum Lines 8 thru 11	
13	**Transmission Accumulated Deferred Taxes**	II.A.1.f						
14	Accumulated Deferred Taxes (190)		63,896,752		13.6034%	8,692,119	Sheet 8, Line 12, col (d)	(a)
15	Accumulated Deferred Income Taxes (281)		-			-	FF1 Page 113.62(c)	(a)
16	Accumulated Deferred Taxes - Property (282)		(1,143,462,163)				FF1 Page 275.9(k)	(a)
17	Less Transition Property		-				FF1 Page 275.4(k)	(a)
18	Net Acc. Def. Income Taxes - Other Property (282)		(1,143,462,163)	Plant	28.7026%	(328,203,371)	Sum Lines 16 thru 17	
19	Accumulated Deferred Income Taxes - Other (283)		(506,588,448)		9.5073%	(48,162,981)	Sheet 8, Line 27, col (d)	(a)
20	Total					(367,674,233)	Line 14 + Line 15 + Line 18 + Line 19	(a)
21	**AFUDC Regulatory Liability**	II.A.1.g	(4,435,570)	Direct	100.0000%	(4,435,570)	FF1 Page 278.3(f)	(a)
								(a)
22	**Gain/Loss on Reacquired Debt**	II.A.1.h	12,865,994	Plant	28.7026%	3,692,875	FF1 Page 111.81(c) + FF1 Page 113.61(c)	(a)
23	**Other Regulatory Assets**	II.A.1.i						
24	Unamortized Balance of Transmission Merger-Related Costs		$ 7,620,390	Direct	100.0000%	7,620,390	**Exhibit No. ES-220, Page 2 of 8, Line 3(B)**	(b)
25	FAS 106 (182.3 & 254)		-	W&S	12.8871%	-	FF1 Page 232	(a)
26	ASC 740 (182.3 - FAS 109)		87,768,732				FF1 Page 232.29(f)	(a)
27	Less ASC 740 Liability (254 - FAS 109)		(4,015,556)				FF1 Page 278.1(f)	(a)
28	Net ASC 740 (182.3 & 254 - FAS 109)		83,753,176	Plant	28.7026%	24,039,339	Sum Lines 26 thru 27	(a)
29	Total Other Regulatory Assets		91,373,566			31,659,729	Line 25 + line 28	(b)
30	**Prepayments**	II.A.1.j	434,988,820	W&S	12.8871%	56,057,444	FF1 Page 111.57(c) + FF1 Page 232.1.2(f) +Page 232.1.3(f)	(a)
31	**Transmission Materials & Supplies**	II.A.1.k	28,541,503	Direct	100.0000%	28,541,503	FF1 Page 227.8(c) + FF1 Page 227.5(c) Footnote	(a)
32	**Cash Working Capital**	II.A.1.l						
33	Operation & Maintenance Expense		25,099,553	WC	12.5000%	3,137,444	Sheet 1a, Line 24, col (c)	(a)
34	Administrative & General Expense		23,434,949	WC	12.5000%	2,929,369	Sheet 1a, Line 25, col (c)	(c)
35	Transmission Support Expenses		3,811,865	WC	12.5000%	476,483	Sheet 1a, Line 28, col (c)	(a)
36	Total Cash Working Capital		52,346,367			6,543,296	Sum Lines 33 thru 35	(c)

Line	Description	Allocation Factor	Reference	Notes
37	**Description**	**Allocation Factor**	**Reference**	
38	Direct Allocation (Direct)	100.0000%		(a)
39	Wages & Salary (W&S)	12.8871%	Sheet 6, Line 6(c)	(a)
40	Plant Allocation (Plant)	28.7026%	Sheet 6, Line 14(c)	(a)
41	Construction Work in Progress Allocation (CWIP)	50.0000%	Sheet 6, Line 15(c)	(a)
42	Cash Working Capital (WC)	12.50%	Tariff Section II.A.1.l	(a)

43 **Note 1 -** Internal Records identify CWIP projects for rate base, as noted in the Exhibit "2014 Construction Work in Progress" included in this filing.

Notes:
(a) Source of information is the NSTAR Annual Informational Filing submitted to FERC on August 14, 2015 in Docket No. ER07-549 and ER09-1243.
(b) Proposed revisions reflect the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset
(c) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-NSTAR Revenue Requirement Comparison Under Changed Rates
Under Attachment D
For Costs in 2014
Sheet 4

Line	(a) Description	(b) Tariff Section	(c) Total	(d) Allocator	(e) Factor	(f) Allocations LNS Amount	(g) Reference	(h) Notes
1	**Transmission Depreciation and Amortization Expense**	II.B						
2	Transmission Depreciation	II.B.i	$ 41,001,613	Direct	100.0000%	$ 41,001,613	FF1 Page 336.7(f)	(a)
3	General Plant Depreciation and Amortization	II.B.ii	8,991,113	W&S	12.8871%	1,158,694	FF1 Page 336.10(f)	(a)
4	Amortization of Transmission Related Intangible Plant		4,111,761	W&S	12.8871%	529,887	FF1 Page 336.1(f)	(a)
5	Amortization of AFUDC Regulatory Credit		(130,369)			(130,369)	FF1 Page 114.13(c)	(a)
6	Net Amortization of Transmission Related Intangible Plant		$ 3,981,392			$ 399,518	Sum Lines 4 and 5	(a)
7	Total Transmission Depreciation and Amortization Expense		$ 53,974,118			$ 42,559,825	Sum Lines 2, 3 and 6	(a)
8	**Amortization of Gain/Loss on Reacquired Debt**	II.C	$ 999,391	Plant	28.7026%	$ 286,851	FF1 Page 117.64(c) + FF1 Page 117.66(c)	(a)
9	**Transmission Related Amortization of ITC**	II.D	$ (1,310,106)	Plant	28.7026%	$ (376,034)	FF1 Page 114.19(c)	(a)
10	**Transmission Related Municipal Tax Expense**	II.E	$ 120,588,821	Plant	28.7026%	$ 34,612,127	FF1 Page 263.5(i)	(a)
11	**Transmission Related Payroll Tax Expense**	II.F	$ 12,412,619	W&S	12.8871%	$ 1,599,627	FF1 Page 263.10(i)	(a)
12	**Transmission Operation and Maintenance Expense**	II.G						
13	Operation Supervision & Engineering (560)		$ 5,674,265	Direct	100.0000%	5,674,265	FF1 Page 321.83(b)	(a)
14			-	Internal Costs		-	FF1 Page 321.84(b)	(a)
15	Load Dispatch - Reliability (561.1)		1,389,220	Internal Costs		1,389,220	FF1 Page 321.85(b)	(a)
16	Load Dispatch-Monitor and Operate Transmission System (561.2)		1,311,222	Internal Costs		1,311,222	FF1 Page 321.86(b)	(a)
17	Load Dispatch-Transmission Service and Scheduling (561.3)		570,681	Internal Costs		570,681	FF1 Page 321.87(b)	(a)
18	Scheduling, System Control and Dispatch Services (561.4)		12,155,295	External Costs		-	FF1 Page 321.88(b)	(a)
19	Reliability, Planning and Standards Development (561.5)		273,226	Internal Costs		21,719	FF1 Page 321.89(b)	(a)
20	Transmission Service Studies (561.6)		106	Internal Costs		106	FF1 Page 321.90(b)	(a)
21	Generation Interconnection Studies (561.7)		-	Internal Costs		-	FF1 Page 321.91(b)	(a)
22	Reliability, Planning and Standards Development Services (561.8)		53,935	External Costs		-	FF1 Page 321.92(b)	(a)
23	Station Expenses (562)		2,729,963	Direct	100.0000%	2,729,963	FF1 Page 321.93(b)	(a)
24	Overhead Lines Expenses (563)		4,327,839	Direct	100.0000%	4,327,839	FF1 Page 321.94(b)	(a)
25	Underground Lines Expenses (564)		636,122	Direct	100.0000%	636,122	FF1 Page 321.95(b)	(a)
26	Miscellaneous Transmission Expenses (566)		496,506	Direct	100.0000%	496,506	FF1 Page 321.97(b)	(a)
27	Rents (567)		14,755	Direct	100.0000%	14,755	Sheet 5 - Page 1 of 2, Line 3, col (d)	(a)
28	Transmission Maintenance (568 - 573)		7,927,155	Direct	100.0000%	7,927,155	FF1 Page 321.111(b)	(a)
29	Regional Market Expense (575-576)		424,648	External Costs	0.0000%	-	FF1 Page 322.131(b)	(a)
30	Total Transmission O&M Expense		$ 37,984,938			$ 25,099,553	Sum Lines 13 thru 29	(a)
31	**Transmission Related A&G Expenses**	II.H						
32	Administrative and General Expenses	I.B	$ 145,329,829				FF1 Page 323.197(b)	(a)
33	Property Insurance (924)		(926,016)				FF1 Page 323.185(b)	(a)
34	Employee Pensions and Benefits (926)		(51,124,252)				FF1 Page 323.187(b)	(a)
35	Regulatory Commission Expenses (928)		(9,560,209)				FF1 Page 323.189(b)	(a)
36	General Advertising Expenses (930.1)		(32,018)				FF1 Page 323.191(b)	(a)
37	Miscellaneous General Expenses (930.2) - **Note 2**		(52,118)				FF1 Page 232.2.14(e)	(a)
38	Merger-Related Costs		-				FF1 Page 232.2.14(e)	(b)
39	Sub-Total	II.H.1	83,635,216	W&S	12.8871%	10,778,154	Sum Lines 32 thru 38	(b)
40	Property Insurance (924)	II.H.2	926,016	Plant	28.7026%	265,791	Line 33	(a)
41	Employee Pensions and Benefits (926) - **Note 1**	II.H.1	51,124,252	W&S	12.8871%	6,588,433	Line 34	(a)
42	Regulatory Commission Expenses (928)	II.H.3	9,560,209	Footnote	20.8403%	1,992,376	Line 50	(a)
43	Transmission Merger-Related Costs		3,810,195	Footnote	100.0000%	3,810,195	**Exhibit No. ES-220, Page 2 of 8, Line 2(B)**	(b)
44	Total Transmission Related A&G Expenses		$ 149,055,888			$ 23,434,949	Sum Lines 39 thru 42	(b)
45	Regulatory Commission Expenses (928)	II.H.3						(a)
46	Assessment Charged by the MA DPU		$ 6,712,589		0.0000%	$ -	FF1 Page 350.2(d)	(a)
47	Proportionate share of expenses of FERC Assessment Order No. 472		1,992,376	Direct	100.0000%	1,992,376	FF1 Page 350.6(d)	(a)
48	Legal Fees - Distribution		787,573		0.0000%	-	FF1 Page 350.8(d)	(a)
49	Minor items - Distribution		67,671		0.0000%	-	FF1 Page 350.10(d)	(a)
50	Total Regulatory Commission Expenses	II.H.3	$ 9,560,209		20.8403%	$ 1,992,376	Sum Lines 46 thru 49	(a)

Line	Description	Allocation Factor	Reference	Notes
51				
52	Direct Allocation (Direct)	100.0000%		(a)
53	Wages & Salaries Allocation (W&S)	12.8871%	Sheet 6, Line 6(c)	(a)
54	Plant Allocation (Plant)	28.7026%	Sheet 6, Line 14(c)	(a)

55 **Note 1**
56 Included in the Employee Pension and Benefits Expenses are costs related to Post Retirement Benefits other than Pension (PBOP). PBOP costs are determined by an independent actuary
57 as required by ASC 715. The PBOP expense included in Account 926 for 2014 was ($5,000,000) as compared to $4,600,000 in 2013; as shown on the FF1, page 323, footnote.
58 Applying the labor allocator to the total PBOP expense results in $(251,041) of PBOP expense being recovered through the LNS Tariff in 2014, as compared to $249,762 in the prior year.

Line		2014	2013	Reference	Notes
59	PBOP	$ (5,000,000)	$ 4,600,000	Page 323 line 187 footnote	(a)
60	Capitalized PBOP & Other impact adjustment	3,052,000	(1,866,000)	**Note 3**	(a)
61	Net PBOP in account 926	$ (1,948,000)	$ 2,734,000	Line 57 + Line 58	(a)
62	Wages & Salaries Allocation (W&S)	12.8871%	9.1354%	Sheet 6	(a)
63	LNS portion of PBOP	$ (251,041)	$ 249,762	Line 59 x Line 60	(a)

64 **Note 2 -** NSTAR Green Program costs are excludable for Transmission billing purposes. Reflects actual information per Eversource's accounting records.
65 **Note 3** - Reflects actual information per Eversource's accounting records. ;

Notes:
(a) Source of information is the NSTAR Annual Informational Filing submitted to FERC on August 14, 2015 in Docket No. ER07-549 and ER09-1243.
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Exhibit No. ES-225
Schedule 4

Schedule 21-NSTAR Revenue Requirements under the Changed Rates for 2017

Eversource Energy Service Company

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-NSTAR Revenue Requirement Comparison Under Changed Rates
Under Attachment D
For the Calendar year 2017

	(A)	(B)	(C)	
Line	**Description**	**Reference**	**Total NSTAR Electric**	
1	2014 Actual Schedule 21-NSTAR Revenue Requirement	Exhibit No. ES-225, Schedule 4, Page 2 of 5, Note (c)	$ 284,920,619	
2	Estimated 2015 Schedule 21-NSTAR Plant Additions	(1)	$ 196,000,000	
3	Carrying Charge Factor (CCF)	Exhibit No. ES-225, Schedule 2, Page 2 of 5, Note (c)	14.6504%	
4	2015 Incremental Estimated Schedule 21-NSTAR Revenue Requirement	Line 2 x 3	28,714,784	
5	2015 Incremental Estimated Schedule 21-NSTAR CWIP Revenue Requirements	(1)	$ 1,366,439	
6	Total Estimated Schedule 21-NSTAR Revenue Requirement for 2015	Line 1 + 4 + 5	$ 315,001,842	
7	Estimated 2016 Schedule 21-NSTAR Plant Additions	(1)	$ 237,000,000	
8	Carrying Charge Factor (CCF)	Line 3	14.65%	
9	2016 Incremental Estimated Schedule 21-NSTAR Revenue Requirement	Line 7 x 8	34,721,448	
10	Total Estimated Schedule 21-NSTAR Revenue Requirement for 2016	Line 6 + 9 + 10	$ 349,723,290	(2)

Notes:

(1) Based on Eversource's Forecast

(2) The revenue requirements calculations for the calendar year 2016 (including any forecast for 2016) are used as an estimate fo
the revenue requirements for 2017, which are used to calculate the revenue impact of the proposed cost recovery

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-NSTAR Revenue Requirement Comparison Under Changed Rates
Under Attachment D
For Costs in 2014
Sheet 1a

	(a)	(b)		(c)	(d)	(e)
Line	**Description**	**Section**		**Amount**	**Reference**	**Notes**
1	**Investment Base**	II.A.1				
2	Transmission Plant	II.A.1.a	$	1,915,292,693	Sheet 3, Line 1, Col (f)	(a)
3	Transmission Related Intangible & General Plant	II.A.1.b		26,538,303	Sheet 3, Line 4, Col (f)	(a)
4	Transmission Plant Held for Future Use	II.A.1.c		13,571,504	Sheet 3, Line 5, Col (f)	(a)
5	Transmission Related Construction Work in Progress	II.A.1.d		45,961,764	Sheet 3, Line 6, Col (f)	(a)
6	Total Plant			2,001,364,264	Sum Lines 2 thru 5	
7	Trans Related Depreciation and Amortization Reserve	II.A.1.e		(462,609,062)	Sheet 3, Line 12, Col (f)	(a)
8	Transmission Related Accumulated Deferred Taxes	II.A.1.f		(367,674,233)	Sheet 3, Line 20, Col (f)	(a)
9	AFUDC Regulatory Liability	II.A.1.g		(4,435,570)	Sheet 3, Line 21, Col (f)	(a)
10	Total Net Plant			1,166,645,399	Sum Lines 6 thru 9	
11	Transmission Related Gain/Loss on Reacquired Debt	II.A.1.h		3,692,875	Sheet 3, Line 22, Col (f)	(a)
12	Other Trans Related Regulatory Assets/Liabilities	II.A.1.i		27,849,534	Sheet 3, Line 29, Col (f)	(b)
13	Transmission Prepayments	II.A.1.j		56,057,444	Sheet 3, Line 30, Col (f)	(a)
14	Transmission Materials & Supplies	II.A.1.k		28,541,503	Sheet 3, Line 31, Col (f)	(a)
15	Transmission Related Cash Working Capital	II.A.1.l		6,543,296	Sheet 3, Line 36, Col (f)	(b)
16	**Total Investment Base**		$	1,289,330,051	Sum Lines 10 thru 15	(b)
17	**Revenue Requirement**					
18	Investment Return and Income Taxes	II.A.2	$	153,891,856	Sheet 2a, Line 39, Col (c)	(b)
19	Transmission Depreciation and Amortization Expense	II.B		42,559,825	Sheet 4 , Line 7, Col (f)	(a)
20	Amortization of Gain/Loss on Reacquired Debt	II.C		286,851	Sheet 4 , Line 8, Col (f)	(a)
21	Transmission Related Amort. of Investment Tax Credits	II.D		(376,034)	Sheet 4 , Line 9, Col (f)	(a)
22	Transmission Related Municipal Tax Expense	II.E		34,612,127	Sheet 4 , Line 10, Col (f)	(a)
23	Transmission Related Payroll Tax Expense	II.F		1,599,627	Sheet 4 , Line 11, Col (f)	(a)
24	Transmission Operation & Maintenance Expense	II.G		25,099,553	Sheet 4 , Line 30, Col (f)	(a)
25	Transmission Related Administrative and General Expense	II.H		23,434,949	Sheet 4 , Line 44, Col (f)	(b)
26	Transmission Related Integrated Facilities Charges	II.I		-	Sheet 5 - Page 1 of 2, Line 6, Col (d)	(a)
27	Transmission Support Revenues	II.J		(4,509,913)	Sheet 5 - Page 1 of 2, Line 45, Col (d)	(a)
28	Transmission Support Expense	II.K		3,811,865	Sheet 5 - Page 1 of 2, Line 57, Col (d)	(a)
29	Transmission Related Expense from Generators	II.L		-	Sheet 5 - Page 1 of 2, Line 60, Col (d)	(a)
30	Transmission Rents Received from Electric Property	II.M		(3,129,907)	Sheet 5 - Page 2 of 2, Line 66, Col (d)	(a)
31	Short-Term and Non-Firm P-T-P Service Revenues	II.N		-	Sheet 5 - Page 2 of 2, Line 69, Col (d)	(a)
32	Regional Network Services (RNS) Revenues	II.O		(173,183,026)	Sheet 5a, Line 6, Col (d)	(a)
33	Through or Out Revenues	II.P		(275,884)	Sheet 5 - Page 2 of 2, Line 78, Col (d)	(a)
34	ISO-NE Scheduling and Dispatch Revenues	II.Q		(5,576,120)	Sheet 5 - Page 2 of 2, Line 82, Col (d)	(a)
35	**Total LNS Revenue Requirement**		$	98,245,769	Sum Lines 18 thru 34	(b)
36	Wholesale LNS Revenues Received:					
37	MBTA			(904,082)	Sheet 5 - Page 1 of 2, Line 22, Col (c)	(b)
38	Concord			(140,908)	Sheet 5 - Page 1 of 2, Line 23, Col (c)	(b)
39	Massachusetts Port Authority (MASSPORT)			(620,561)	Sheet 5 - Page 1 of 2, Line 24, Col (c)	(b)
40	Nantucket-LNS			(296,522)	Sheet 5 - Page 1 of 2, Line 25, Col (c)	(b)
41	Covanta-SEMass			(133,071)	Sheet 5 - Page 1 of 2, Line 27, Col (c)	(b)
42	Total Wholesale LNS Revenue		$	(2,095,144)	Sum Lines 37 thru 41	(b)
						(b)
43	**Total Retail LNS Revenue Requirement**		**$**	**96,150,625**	Line 35 - Line 42	(b)
						(b)
						(b)
44	Average 12 CP					(b)
45	Sum of Monthly Peaks (kW)			48,920,000	FF1 Page 400.17(b) *1000	(b)
46	Average Peak			4,076,667	Line 45 / 12	(b)
						(b)
47	Annual Rate per kW		$	24.0995	Line 35 / Line 46	(b)
48	Monthly Rate per kW		$	2.0083	Line 47 / 12	(b)
49	Weekly Rate per kW		$	0.4635	Line 47 / 52	(b)
50	Daily Rate per kW		$	0.0660	Line 47 / 365	(b)
51	Hourly Rate per kW		$	0.0028	Line 47 / 8760	(b)

This reflects an ROE of 10.57% per FERC Order in Docket No. EL11-66 dated October 16, 2014.

Notes:

(a) Source of information is the NSTAR Annual Informational Filing submitted to FERC on August 14, 2015 in Docket No. ER07-549 and ER09-1243.
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset
(c) Total LNS Revenue Requirements (Sum Lines 18 - 25 and Line 28) $ 284,920,619

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-NSTAR Revenue Requirement Comparison Under Changed Rates
Under Attachment D
For Costs in 2014
Sheet 2a

Line	(a) Description	(b) Tariff Section	(c) Balance	(d) Capitalization Ratio	(e) Cost	(f) Weighted Cost	(g) Equity Cost	(h) Reference	(i) Notes
1	**Weighted Cost of Capital**	II.A.2.a							
2	Long Term Debt	II.A.2.a.i	$ 1,792,712,148	41.74%	4.19%	1.75%		FF1 Page 112.24(c)	(a)
3	Preferred Stock	II.A.2.a.ii	43,000,000	1.00%	4.56%	0.05%	0.05%	FF1 Page 112.3(c)	(a)
4	Common Equity	II.A.2.a.iii	2,459,452,736	57.26%	10.57%	6.05%	6.05%	FF1 Page 112.16(c) - Line 3(c)	(a)
5	Total		$ 4,295,164,884			7.85%	6.10%	Sum Lines 2 thru 4	(a)

ROE per ISO New England Inc. Transmission, Markets and Services Tariff, Schedule 21-NSTAR Attachment D II.A.2.(a)(iii), page 60
http://www.iso-ne.com/regulatory/tariff/sect_2/sch21/sch_21_nstar.pdf

Line	Description	Tariff Section	Balance	Reference	Notes
6	**Investment Return**	II.A.2			
7	Total Investment Base		$ 1,289,330,051	Sheet 1, Line 16, Col (c)	(b)
8	Weighted Cost of Capital		7.85%	Line 5, Col (f)	(a)
9	Total Return on Investment		**$ 101,212,409**	Line 7 * Line 8	(b)
10	**Federal Income Tax**	II.A.2.b			
11	A = Equity Cost		6.10%	Line 5, Col (g)	(a)
12	B = Transmission Amortization of ITC		$ (376,034)	Sheet 1, Line 21, Col (c)	(a)
13	C = Equity AFUDC		91,676	FF1 Page 336.7(b) Footnote + FF1 Page 336.10(b) Footnote	(a)
14	Total B + C		(284,358)	Line 12 + Line 13	(a)
15	D = Investment Base		1,289,330,051	Line 7	(b)
16	(B + C) / D		-0.0221%	Line 14 / Line 15	(b)
17	(A + [(C + B) / D]		6.0779%	Line 11 + Line 16	(b)
18	FT = Federal Income Tax Rate		35.00%	Federal corporate tax rate	(a)
19	1 - FT		65.00%	1 - Line 18	(a)
20	Federal Tax Factor		3.2727%	Line 17 * Line 18 / Line 19	(a)
21	Total Federal Income Taxes		**$ 42,195,905**	Line 15 * Line 20	(b)
22	**State Income Tax**	II.A.2.c			
23	A = Equity Cost		6.10%	Line 5, Col (g)	(a)
24	B = Transmission Amortization of ITC		$ (376,034)	Sheet 1, Line 21, Col (c)	(a)
25	C = Equity AFUDC		91,676	FF1 Page 336.7(b) Footnote + FF1 Page 336.10(b) Footnote	(a)
26	Total B + C		(284,358)	Line 24 + Line 25	(a)
27	D = Investment Base		1,289,330,051	Line 7	(b)
28	(B + C) / D		-0.0221%	Line 26 / Line 27	(b)
29	(A + [(C + B) / D]		6.0779%	Line 23 + Line 28	(b)
30	ST = State Income Tax Rate		8.00%	Massachusetts corporate tax rate	(a)
31	1 - ST		92.00%	1 - Line 30	(a)
32	Federal Tax Factor		3.2727%	Line 20	(a)
33	State Tax Factor		0.8131%	(Line 29 + Line 32) * Line 30 / Line 31	(a)
34	Total State Income Taxes		**$ 10,483,543**	Line 27 * Line 33	(b)
35	**Investment Return and Income Taxes**	II.A.2			
36	Return on Investment		$ 101,212,409	Line 9	(b)
37	Federal Income Taxes		42,195,905	Line 21	(b)
38	State Income Taxes		10,483,543	Line 34	(b)
39	**Total Return and Income Taxes**		**$ 153,891,856**	Sum Lines 36 thru 38	(b)

Notes:
(a) Source of information is the NSTAR Annual Informational Filing submitted to FERC on August 14, 2015 in Docket No. ER07-549 and ER09-1243.
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-NSTAR Revenue Requirement Comparison Under Changed Rates
Under Attachment D
For Costs in 2014
Sheet 3

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		Tariff		Allocations				
Line	Description	Section	Total	Allocator	Factor	LNS Amount	Reference	Notes
1	**Transmission Plant**	II.A.1.a	$ 1,915,292,693	Direct	100.0000%	$ 1,915,292,693	FF1 Page 207.58(g)	(a)
2	General Plant		186,941,660	W&S	12.8871%	24,091,359	FF1 Page 207.99(g)	(a)
3	Intangible Plant		18,987,542	W&S	12.8871%	2,446,944	FF1 Page 205.5(g)	(a)
4	**Total Intangible & General Plant**	II.A.1.b				26,538,303	Sum Lines 2 thru 3	
5	**Transmission Plant Held for Future Use**	II.A.1.c	13,571,504	Direct	100.0000%	13,571,504	FF1 Page 214.14(d) + FF1 Page 214.15(d) + FF1 Page 214.16(d) + FF1 Page 214.17(d) + FF1 Page 214.18(d)	(a)
6	**Transmission Related CWIP - Note 1**	II.A.1.d	91,923,527	CWIP	50.0000%	45,961,764	FF1 Page 216, lines 32(b), 34(b) thru 42(b), and Page 216.1, lines 1(b), 2(b), 5(b), 6(b), 10(b) thru 12(b) 14(part)(b) Trans only	(a)
7	**Transmission Related Dep & Amort Reserve**	II.A.1.e						
8	Transmission Accumulated Depreciation		(453,776,651)	Direct	100.0000%	(453,776,651)	FF1 Page 219.25(b)	(a)
9	General Plant Accumulated Depreciation		(52,490,917)	W&S	12.8871%	(6,764,557)	FF1 Page 219.28(b)	(a)
10	General Plant Accumulated Amortization		(6,245,258)	W&S	12.8871%	(804,833)	FF1 Page 200.21(c) Footnote	(a)
11	Intangible Plant Accumulated Amortization		(9,800,663)	W&S	12.8871%	(1,263,021)	FF1 Page 200.21(c) Footnote	(a)
12	Total Transmission Related Depreciation Reserve		(522,313,489)			(462,609,062)	Sum Lines 8 thru 11	(a)
13	**Transmission Accumulated Deferred Taxes**	II.A.1.f						
14	Accumulated Deferred Taxes (190)		63,896,752		13.6034%	8,692,119	Sheet 8, Line 12, col (d)	(a)
15	Accumulated Deferred Income Taxes (281)		-			-	FF1 Page 113.62(c)	(a)
16	Accumulated Deferred Taxes - Property (282)		(1,143,462,163)				FF1 Page 275.9(k)	(a)
17	Less Transition Property		-				FF1 Page 275.4(k)	(a)
18	Net Acc. Def. Income Taxes - Other Property (282)		(1,143,462,163)	Plant	28.7026%	(328,203,371)	Sum Lines 16 thru 17	(a)
19	Accumulated Deferred Income Taxes - Other (283)		(506,588,448)		9.5073%	(48,162,981)	Sheet 8, Line 27, col (d)	(a)
20	Total					(367,674,233)	Line 14 + Line 15 + Line 18 + Line 19	(a)
21	**AFUDC Regulatory Liability**	II.A.1.g	(4,435,570)	Direct	100.0000%	(4,435,570)	FF1 Page 278.3(f)	(a)
								(a)
22	**Gain/Loss on Reacquired Debt**	II.A.1.h	12,865,994	Plant	28.7026%	3,692,875	FF1 Page 111.81(c) + FF1 Page 113.61(c)	
23	**Other Regulatory Assets**	II.A.1.i						
24	Unamortized Balance of Transmission Merger-Related Costs		$ 3,810,195	Direct	100.0000%	3,810,195	**Exhibit No. ES-220, Page 2 of 8, Line 3(C)**	(b)
25	FAS 106 (182.3 & 254)		-	W&S	12.8871%	-	FF1 Page 232	(a)
26	ASC 740 (182.3 - FAS 109)		87,768,732				FF1 Page 232.29(f)	(a)
27	Less ASC 740 Liability (254 - FAS 109)		(4,015,556)				FF1 Page 278.1(f)	(a)
28	Net ASC 740 (182.3 & 254 - FAS 109)		83,753,176	Plant	28.7026%	24,039,339	Sum Lines 26 thru 27	(a)
29	Total Other Regulatory Assets		87,563,371			27,849,534	Line 25 + line 28	(b)
30	**Prepayments**	II.A.1.j	434,988,820	W&S	12.8871%	56,057,444	FF1 Page 111.57(c) + FF1 Page 232.1.2(f) +Page 232.1.3(f)	(a)
31	**Transmission Materials & Supplies**	II.A.1.k	28,541,503	Direct	100.0000%	28,541,503	FF1 Page 227.8(c) + FF1 Page 227.5(c) Footnote	(a)
32	**Cash Working Capital**	II.A.1.l						
33	Operation & Maintenance Expense		25,099,553	WC	12.5000%	3,137,444	Sheet 1a, Line 24, col (c)	(a)
34	Administrative & General Expense		23,434,949	WC	12.5000%	2,929,369	Sheet 1a, Line 25, col (c)	(c)
35	Transmission Support Expenses		3,811,865	WC	12.5000%	476,483	Sheet 1a, Line 28, col (c)	(a)
36	Total Cash Working Capital		52,346,367			6,543,296	Sum Lines 33 thru 35	(c)

Line	Description	Allocation Factor	Reference	Notes
37				
38	Direct Allocation (Direct)	100.0000%		(a)
39	Wages & Salary (W&S)	12.8871%	Sheet 6, Line 6(c)	(a)
40	Plant Allocation (Plant)	28.7026%	Sheet 6, Line 14(c)	(a)
41	Construction Work in Progress Allocation (CWIP)	50.0000%	Sheet 6, Line 15(c)	(a)
42	Cash Working Capital (WC)	12.50%	Tariff Section II.A.1.l	(a)

43 **Note 1 -** Internal Records identify CWIP projects for rate base, as noted in the Exhibit "2014 Construction Work in Progress" included in this filing.

Notes:
(a) Source of information is the NSTAR Annual Informational Filing submitted to FERC on August 14, 2015 in Docket No. ER07-549 and ER09-1243.
(b) Proposed revisions reflect the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset
(c) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-NSTAR Revenue Requirement Comparison Under Changed Rates
Under Attachment D
For Costs in 2014
Sheet 4

Line	(a) Description	(b) Tariff Section	(c) Total	(d) Allocator	(e) Factor	(f) Allocations LNS Amount	(g) Reference	(h) Notes
1	**Transmission Depreciation and Amortization Expense**	II.B						
2	Transmission Depreciation	II.B.i	$ 41,001,613	Direct	100.0000%	$ 41,001,613	FF1 Page 336.7(f)	(a)
3	General Plant Depreciation and Amortization	II.B.ii	8,991,113	W&S	12.8871%	1,158,694	FF1 Page 336.10(f)	(a)
4	Amortization of Transmission Related Intangible Plant		4,111,761	W&S	12.8871%	529,887	FF1 Page 336.1(f)	(a)
5	Amortization of AFUDC Regulatory Credit		(130,369)			(130,369)	FF1 Page 114.13(c)	(a)
6	Net Amortization of Transmission Related Intangible Plant		$ 3,981,392			$ 399,518	Sum Lines 4 and 5	(a)
7	Total Transmission Depreciation and Amortization Expense		$ 53,974,118			$ 42,559,825	Sum Lines 2, 3 and 6	(a)
8	**Amortization of Gain/Loss on Reacquired Debt**	II.C	$ 999,391	Plant	28.7026%	$ 286,851	FF1 Page 117.64(c) + FF1 Page 117.66(c)	(a)
9	**Transmission Related Amortization of ITC**	II.D	$ (1,310,106)	Plant	28.7026%	$ (376,034)	FF1 Page 114.19(c)	(a)
10	**Transmission Related Municipal Tax Expense**	II.E	$ 120,588,821	Plant	28.7026%	$ 34,612,127	FF1 Page 263.5(i)	(a)
11	**Transmission Related Payroll Tax Expense**	II.F	$ 12,412,619	W&S	12.8871%	$ 1,599,627	FF1 Page 263.10(i)	(a)
12	**Transmission Operation and Maintenance Expense**	II.G						
13	Operation Supervision & Engineering (560)		$ 5,674,265	Direct	100.0000%	5,674,265	FF1 Page 321.83(b)	(a)
14			-	Internal Costs		-	FF1 Page 321.84(b)	(a)
15	Load Dispatch - Reliability (561.1)		1,389,220	Internal Costs		1,389,220	FF1 Page 321.85(b)	(a)
16	Load Dispatch-Monitor and Operate Transmission System (561.2)		1,311,222	Internal Costs		1,311,222	FF1 Page 321.86(b)	(a)
17	Load Dispatch-Transmission Service and Scheduling (561.3)		570,681	Internal Costs		570,681	FF1 Page 321.87(b)	(a)
18	Scheduling, System Control and Dispatch Services (561.4)		12,155,295	External Costs		-	FF1 Page 321.88(b)	(a)
19	Reliability, Planning and Standards Development (561.5)		273,226	Internal Costs		21,719	FF1 Page 321.89(b)	(a)
20	Transmission Service Studies (561.6)		106	Internal Costs		106	FF1 Page 321.90(b)	(a)
21	Generation Interconnection Studies (561.7)		-	Internal Costs		-	FF1 Page 321.91(b)	(a)
22	Reliability, Planning and Standards Development Services (561.8)		53,935	External Costs		-	FF1 Page 321.92(b)	(a)
23	Station Expenses (562)		2,729,963	Direct	100.0000%	2,729,963	FF1 Page 321.93(b)	(a)
24	Overhead Lines Expenses (563)		4,327,839	Direct	100.0000%	4,327,839	FF1 Page 321.94(b)	(a)
25	Underground Lines Expenses (564)		636,122	Direct	100.0000%	636,122	FF1 Page 321.95(b)	(a)
26	Miscellaneous Transmission Expenses (566)		496,506	Direct	100.0000%	496,506	FF1 Page 321.97(b)	(a)
27	Rents (567)		14,755	Direct	100.0000%	14,755	Sheet 5 - Page 1 of 2, Line 3, col (d)	(a)
28	Transmission Maintenance (568 - 573)		7,927,155	Direct	100.0000%	7,927,155	FF1 Page 321.111(b)	(a)
29	Regional Market Expense (575-576)		424,648	External Costs	0.0000%	-	FF1 Page 322.131(b)	(a)
30	Total Transmission O&M Expense		$ 37,984,938			$ 25,099,553	Sum Lines 13 thru 29	(a)
31	**Transmission Related A&G Expenses**	II.H						
32	Administrative and General Expenses	I.B	$ 145,329,829				FF1 Page 323.197(b)	(a)
33	Property Insurance (924)		(926,016)				FF1 Page 323.185(b)	(a)
34	Employee Pensions and Benefits (926)		(51,124,252)				FF1 Page 323.187(b)	(a)
35	Regulatory Commission Expenses (928)		(9,560,209)				FF1 Page 323.189(b)	(a)
36	General Advertising Expenses (930.1)		(32,018)				FF1 Page 323.191(b)	(a)
37	Miscellaneous General Expenses (930.2) - **Note 2**		(52,118)				FF1 Page 232.2.14(e)	(a)
38	Merger-Related Costs		-				FF1 Page 232.2.14(e)	(b)
39	Sub-Total	II.H.1	83,635,216	W&S	12.8871%	10,778,154	Sum Lines 32 thru 38	(b)
40	Property Insurance (924)	II.H.2	926,016	Plant	28.7026%	265,791	Line 33	(a)
41	Employee Pensions and Benefits (926) - **Note 1**	II.H.1	51,124,252	W&S	12.8871%	6,588,433	Line 34	(a)
42	Regulatory Commission Expenses (928)	II.H.3	9,560,209	Footnote	20.8403%	1,992,376	Line 50	(a)
43	Transmission Merger-Related Costs		3,810,195	Footnote	100.0000%	3,810,195	**Exhibit No. ES-220, Page 2 of 8, Line 2(C)**	(b)
44	Total Transmission Related A&G Expenses		$ 149,055,888			$ 23,434,949	Sum Lines 39 thru 42	(b)
45	Regulatory Commission Expenses (928)	II.H.3						(a)
46	Assessment Charged by the MA DPU		$ 6,712,589		0.0000%	$ -	FF1 Page 350.2(d)	(a)
47	Proportionate share of expenses of FERC Assessment Order No. 472		1,992,376	Direct	100.0000%	1,992,376	FF1 Page 350.6(d)	(a)
48	Legal Fees - Distribution		787,573		0.0000%	-	FF1 Page 350.8(d)	(a)
49	Minor items - Distribution		67,671		0.0000%	-	FF1 Page 350.10(d)	(a)
50	Total Regulatory Commission Expenses	II.H.3	$ 9,560,209		20.8403%	$ 1,992,376	Sum Lines 46 thru 49	(a)

Line	Description	Allocation Factor	Reference	Notes
51				
52	Direct Allocation (Direct)	100.0000%		(a)
53	Wages & Salaries Allocation (W&S)	12.8871%	Sheet 6, Line 6(c)	(a)
54	Plant Allocation (Plant)	28.7026%	Sheet 6, Line 14(c)	(a)

55 **Note 1**
56 Included in the Employee Pension and Benefits Expenses are costs related to Post Retirement Benefits other than Pension (PBOP). PBOP costs are determined by an independent actuary
57 as required by ASC 715. The PBOP expense included in Account 926 for 2014 was ($5,000,000) as compared to $4,600,000 in 2013; as shown on the FF1, page 323, footnote.
58 Applying the labor allocator to the total PBOP expense results in $(251,041) of PBOP expense being recovered through the LNS Tariff in 2014, as compared to $249,762 in the prior year.

Line		2014	2013	Reference	Notes
59	PBOP	$ (5,000,000)	$ 4,600,000	Page 323 line 187 footnote	(a)
60	Capitalized PBOP & Other impact adjustment	3,052,000	(1,866,000)	**Note 3**	(a)
61	Net PBOP in account 926	$ (1,948,000)	$ 2,734,000	Line 57 + Line 58	(a)
62	Wages & Salaries Allocation (W&S)	12.8871%	9.1354%	Sheet 6	(a)
63	LNS portion of PBOP	$ (251,041)	$ 249,762	Line 59 x Line 60	(a)

64 **Note 2 -** NSTAR Green Program costs are excludable for Transmission billing purposes. Reflects actual information per Eversource's accounting records.
65 **Note 3** - Reflects actual information per Ecersources' accounting records. ;

Notes:
(a) Source of information is the NSTAR Annual Informational Filing submitted to FERC on August 14, 2015 in Docket No. ER07-549 and ER09-1243.
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Exhibit No. ES-225
Schedule 5

Schedule 21-NSTAR Revenue Requirements under the Changed Rates for 2018

Eversource Energy Service Company

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-NSTAR Revenue Requirement Comparison Under Changed Rates
Under Attachment D
For the Calendar year 2018

	(A)	(B)	(C)	
Line	**Description**	**Reference**	**Total NSTAR Electric**	
1	2014 Actual Schedule 21-NSTAR Revenue Requirement	Exhibit No. ES-225, Schedule 5, Page 2 of 5, Note (c)	$ 284,465,842	
2	Estimated 2015 Schedule 21-NSTAR Plant Additions	(1)	$ 196,000,000	
3	Carrying Charge Factor (CCF)	Exhibit No. ES-225, Schedule 2, Page 2 of 5, Note (c)	14.6504%	
4	2015 Incremental Estimated Schedule 21-NSTAR Revenue Requirement	Line 2 x 3	28,714,784	
5	2015 Incremental Estimated Schedule 21-NSTAR CWIP Revenue Requirements	(1)	$ 1,366,439	
6	Total Estimated Schedule 21-NSTAR Revenue Requirement for 2015	Line 1 + 4 + 5	$ 314,547,065	
7	Estimated 2016 Schedule 21-NSTAR Plant Additions	(1)	$ 237,000,000	
8	Carrying Charge Factor (CCF)	Line 3	14.65%	
9	2016 Incremental Estimated Schedule 21-NSTAR Revenue Requirement	Line 7 x 8	34,721,448	
10	Total Estimated Schedule 21-NSTAR Revenue Requirement for 2016	Line 6 + 9 + 10	$ 349,268,513	(2)

Notes:
(1) Based on Eversource's Forecast
(2) The revenue requirements calculations for the calendar year 2016 (including any forecast for 2016) are used as an estimate fo the revenue requirements for 2018, which are used to calculate the revenue impact of the proposed cost recovery.

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-NSTAR Revenue Requirement Comparison Under Changed Rates
Under Attachment D
For Costs in 2014
Sheet 1a

	(a)	(b)		(c)	(d)	(e)
Line	**Description**	**Section**		**Amount**	**Reference**	**Notes**
1	**Investment Base**	II.A.1				
2	Transmission Plant	II.A.1.a	$	1,915,292,693	Sheet 3, Line 1, Col (f)	(a)
3	Transmission Related Intangible & General Plant	II.A.1.b		26,538,303	Sheet 3, Line 4, Col (f)	(a)
4	Transmission Plant Held for Future Use	II.A.1.c		13,571,504	Sheet 3, Line 5, Col (f)	(a)
5	Transmission Related Construction Work in Progress	II.A.1.d		45,961,764	Sheet 3, Line 6, Col (f)	(a)
6	Total Plant			2,001,364,264	Sum Lines 2 thru 5	
7	Trans Related Depreciation and Amortization Reserve	II.A.1.e		(462,609,062)	Sheet 3, Line 12, Col (f)	(a)
8	Transmission Related Accumulated Deferred Taxes	II.A.1.f		(367,674,233)	Sheet 3, Line 20, Col (f)	(a)
9	AFUDC Regulatory Liability	II.A.1.g		(4,435,570)	Sheet 3, Line 21, Col (f)	(a)
10	Total Net Plant			1,166,645,399	Sum Lines 6 thru 9	
11	Transmission Related Gain/Loss on Reacquired Debt	II.A.1.h		3,692,875	Sheet 3, Line 22, Col (f)	(a)
12	Other Trans Related Regulatory Assets/Liabilities	II.A.1.i		24,039,339	Sheet 3, Line 29, Col (f)	(b)
13	Transmission Prepayments	II.A.1.j		56,057,444	Sheet 3, Line 30, Col (f)	(a)
14	Transmission Materials & Supplies	II.A.1.k		28,541,503	Sheet 3, Line 31, Col (f)	(a)
15	Transmission Related Cash Working Capital	II.A.1.l		6,543,296	Sheet 3, Line 36, Col (f)	(b)
16	**Total Investment Base**		$	1,285,519,856	Sum Lines 10 thru 15	(b)
17	**Revenue Requirement**					
18	Investment Return and Income Taxes	II.A.2	$	153,437,079	Sheet 2a, Line 39, Col (c)	(b)
19	Transmission Depreciation and Amortization Expense	II.B		42,559,825	Sheet 4 , Line 7, Col (f)	(a)
20	Amortization of Gain/Loss on Reacquired Debt	II.C		286,851	Sheet 4 , Line 8, Col (f)	(a)
21	Transmission Related Amort. of Investment Tax Credits	II.D		(376,034)	Sheet 4 , Line 9, Col (f)	(a)
22	Transmission Related Municipal Tax Expense	II.E		34,612,127	Sheet 4 , Line 10, Col (f)	(a)
23	Transmission Related Payroll Tax Expense	II.F		1,599,627	Sheet 4 , Line 11, Col (f)	(a)
24	Transmission Operation & Maintenance Expense	II.G		25,099,553	Sheet 4 , Line 30, Col (f)	(a)
25	Transmission Related Administrative and General Expense	II.H		23,434,949	Sheet 4 , Line 44, Col (f)	(b)
26	Transmission Related Integrated Facilities Charges	II.I		-	Sheet 5 - Page 1 of 2, Line 6, Col (d)	(a)
27	Transmission Support Revenues	II.J		(4,509,913)	Sheet 5 - Page 1 of 2, Line 45, Col (d)	(a)
28	Transmission Support Expense	II.K		3,811,865	Sheet 5 - Page 1 of 2, Line 57, Col (d)	(a)
29	Transmission Related Expense from Generators	II.L		-	Sheet 5 - Page 1 of 2, Line 60, Col (d)	(a)
30	Transmission Rents Received from Electric Property	II.M		(3,129,907)	Sheet 5 - Page 2 of 2, Line 66, Col (d)	(a)
31	Short-Term and Non-Firm P-T-P Service Revenues	II.N		-	Sheet 5 - Page 2 of 2, Line 69, Col (d)	(a)
32	Regional Network Services (RNS) Revenues	II.O		(173,183,026)	Sheet 5a, Line 6, Col (d)	(a)
33	Through or Out Revenues	II.P		(275,884)	Sheet 5 - Page 2 of 2, Line 78, Col (d)	(a)
34	ISO-NE Scheduling and Dispatch Revenues	II.Q		(5,576,120)	Sheet 5 - Page 2 of 2, Line 82, Col (d)	(a)
35	**Total LNS Revenue Requirement**		$	97,790,992	Sum Lines 18 thru 34	(b)
36	Wholesale LNS Revenues Received:					
37	MBTA			(904,082)	Sheet 5 - Page 1 of 2, Line 22, Col (c)	(b)
38	Concord			(140,908)	Sheet 5 - Page 1 of 2, Line 23, Col (c)	(b)
39	Massachusetts Port Authority (MASSPORT)			(620,561)	Sheet 5 - Page 1 of 2, Line 24, Col (c)	(b)
40	Nantucket-LNS			(296,522)	Sheet 5 - Page 1 of 2, Line 25, Col (c)	(b)
41	Covanta-SEMass			(133,071)	Sheet 5 - Page 1 of 2, Line 27, Col (c)	(b)
42	Total Wholesale LNS Revenue		$	(2,095,144)	Sum Lines 37 thru 41	(b)
						(b)
43	**Total Retail LNS Revenue Requirement**		**$**	**95,695,848**	Line 35 - Line 42	(b)
						(b)
						(b)
44	Average 12 CP					(b)
45	Sum of Monthly Peaks (kW)			48,920,000	FF1 Page 400.17(b) *1000	(b)
46	Average Peak			4,076,667	Line 45 / 12	(b)
						(b)
47	Annual Rate per kW		$	23.9880	Line 35 / Line 46	(b)
48	Monthly Rate per kW		$	1.9990	Line 47 / 12	(b)
49	Weekly Rate per kW		$	0.4613	Line 47 / 52	(b)
50	Daily Rate per kW		$	0.0657	Line 47 / 365	(b)
51	Hourly Rate per kW		$	0.0027	Line 47 / 8760	(b)

This reflects an ROE of 10.57% per FERC Order in Docket No. EL11-66 dated October 16, 2014.

Notes:

(a) Source of information is the NSTAR Annual Informational Filing submitted to FERC on August 14, 2015 in Docket No. ER07-549 and ER09-1243.
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset
(c) Total LNS Revenue Requirements (Sum Lines 18 - 25 and Line 28) $ 284,465,842

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-NSTAR Revenue Requirement Comparison Under Changed Rates
Under Attachment D
For Costs in 2014
Sheet 2a

Line	(a) Description	(b) Tariff Section	(c) Balance	(d) Capitalization Ratio	(e) Cost	(f) Weighted Cost	(g) Equity Cost	(h) Reference	(i) Notes
1	**Weighted Cost of Capital**	II.A.2.a							
2	Long Term Debt	II.A.2.a.i	$ 1,792,712,148	41.74%	4.19%	1.75%		FF1 Page 112.24(c)	(a)
3	Preferred Stock	II.A.2.a.ii	43,000,000	1.00%	4.56%	0.05%	0.05%	FF1 Page 112.3(c)	(a)
4	Common Equity	II.A.2.a.iii	2,459,452,736	57.26%	10.57%	6.05%	6.05%	FF1 Page 112.16(c) - Line 3(c)	(a)
5	Total		$ 4,295,164,884			7.85%	6.10%	Sum Lines 2 thru 4	(a)

ROE per ISO New England Inc. Transmission, Markets and Services Tariff, Schedule 21-NSTAR Attachment D II.A.2.(a)(iii), page 60
http://www.iso-ne.com/regulatory/tariff/sect_2/sch21/sch_21_nstar.pdf

Line	(a) Description	(b) Tariff Section	(c) Balance	(h) Reference	(i) Notes
6	**Investment Return**	II.A.2			
7	Total Investment Base		$ 1,285,519,856	Sheet 1, Line 16, Col (c)	(b)
8	Weighted Cost of Capital		7.85%	Line 5, Col (f)	(a)
9	Total Return on Investment		**$ 100,913,309**	Line 7 * Line 8	(b)
10	**Federal Income Tax**	II.A.2.b			
11	A = Equity Cost		6.10%	Line 5, Col (g)	(a)
12	B = Transmission Amortization of ITC		$ (376,034)	Sheet 1, Line 21, Col (c)	(a)
13	C = Equity AFUDC		91,676	FF1 Page 336.7(b) Footnote + FF1 Page 336.10(b) Footnote	(a)
14	Total B + C		(284,358)	Line 12 + Line 13	(a)
15	D = Investment Base		1,285,519,856	Line 7	(b)
16	(B + C) / D		-0.0221%	Line 14 / Line 15	(a)
17	(A + [(C + B) / D]		6.0779%	Line 11 + Line 16	(a)
18	FT = Federal Income Tax Rate		35.00%	Federal corporate tax rate	(a)
19	1 - FT		65.00%	1 - Line 18	(a)
20	Federal Tax Factor		3.2727%	Line 17 * Line 18 / Line 19	(a)
21	Total Federal Income Taxes		**$ 42,071,208**	Line 15 * Line 20	(b)
22	**State Income Tax**	II.A.2.c			
23	A = Equity Cost		6.10%	Line 5, Col (g)	(a)
24	B = Transmission Amortization of ITC		$ (376,034)	Sheet 1, Line 21, Col (c)	(a)
25	C = Equity AFUDC		91,676	FF1 Page 336.7(b) Footnote + FF1 Page 336.10(b) Footnote	(a)
26	Total B + C		(284,358)	Line 24 + Line 25	(a)
27	D = Investment Base		1,285,519,856	Line 7	(b)
28	(B + C) / D		-0.0221%	Line 26 / Line 27	(a)
29	(A + [(C + B) / D]		6.0779%	Line 23 + Line 28	(a)
30	ST = State Income Tax Rate		8.00%	Massachusetts corporate tax rate	(a)
31	1 - ST		92.00%	1 - Line 30	(a)
32	Federal Tax Factor		3.2727%	Line 20	(a)
33	State Tax Factor		0.8131%	(Line 29 + Line 32) * Line 30 / Line 31	(a)
34	Total State Income Taxes		**$ 10,452,562**	Line 27 * Line 33	(b)
35	**Investment Return and Income Taxes**	II.A.2			
36	Return on Investment		$ 100,913,309	Line 9	(b)
37	Federal Income Taxes		42,071,208	Line 21	(b)
38	State Income Taxes		10,452,562	Line 34	(b)
39	**Total Return and Income Taxes**		**$ 153,437,079**	Sum Lines 36 thru 38	(b)

Notes:
(a) Source of information is the NSTAR Annual Informational Filing submitted to FERC on August 14, 2015 in Docket No. ER07-549 and ER09-1243.
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-NSTAR Revenue Requirement Comparison Under Changed Rates
Under Attachment D
For Costs in 2014
Sheet 3

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		Tariff		Allocations				
Line	Description	Section	Total	Allocator	Factor	LNS Amount	Reference	Notes
1	**Transmission Plant**	II.A.1.a	$ 1,915,292,693	Direct	100.0000%	$ 1,915,292,693	FF1 Page 207.58(g)	(a)
2	General Plant		186,941,660	W&S	12.8871%	24,091,359	FF1 Page 207.99(g)	(a)
3	Intangible Plant		18,987,542	W&S	12.8871%	2,446,944	FF1 Page 205.5(g)	(a)
4	**Total Intangible & General Plant**	II.A.1.b				26,538,303	Sum Lines 2 thru 3	
5	**Transmission Plant Held for Future Use**	II.A.1.c	13,571,504	Direct	100.0000%	13,571,504	FF1 Page 214.14(d) + FF1 Page 214.15(d) + FF1 Page 214.16(d) + FF1 Page 214.17(d) + FF1 Page 214.18(d)	(a)
6	**Transmission Related CWIP - Note 1**	II.A.1.d	91,923,527	CWIP	50.0000%	45,961,764	FF1 Page 216, lines 32(b), 34(b) thru 42(b), and Page 216.1, lines 1(b), 2(b), 5(b), 6(b), 10(b) thru 12(b) 14(part)(b) Trans only	(a)
7	**Transmission Related Dep & Amort Reserve**	II.A.1.e						
8	Transmission Accumulated Depreciation		(453,776,651)	Direct	100.0000%	(453,776,651)	FF1 Page 219.25(b)	(a)
9	General Plant Accumulated Depreciation		(52,490,917)	W&S	12.8871%	(6,764,557)	FF1 Page 219.28(b)	(a)
10	General Plant Accumulated Amortization		(6,245,258)	W&S	12.8871%	(804,833)	FF1 Page 200.21(c) Footnote	(a)
11	Intangible Plant Accumulated Amortization		(9,800,663)	W&S	12.8871%	(1,263,021)	FF1 Page 200.21(c) Footnote	(a)
12	Total Transmission Related Depreciation Reserve		(522,313,489)			(462,609,062)	Sum Lines 8 thru 11	(a)
13	**Transmission Accumulated Deferred Taxes**	II.A.1.f						
14	Accumulated Deferred Taxes (190)		63,896,752		13.6034%	8,692,119	Sheet 8, Line 12, col (d)	(a)
15	Accumulated Deferred Income Taxes (281)		-			-	FF1 Page 113.62(c)	(a)
16	Accumulated Deferred Taxes - Property (282)		(1,143,462,163)				FF1 Page 275.9(k)	(a)
17	Less Transition Property		-				FF1 Page 275.4(k)	(a)
18	Net Acc. Def. Income Taxes - Other Property (282)		(1,143,462,163)	Plant	28.7026%	(328,203,371)	Sum Lines 16 thru 17	
19	Accumulated Deferred Income Taxes - Other (283)		(506,588,448)		9.5073%	(48,162,981)	Sheet 8, Line 27, col (d)	(a)
20	Total					(367,674,233)	Line 14 + Line 15 + Line 18 + Line 19	(a)
21	**AFUDC Regulatory Liability**	II.A.1.g	(4,435,570)	Direct	100.0000%	(4,435,570)	FF1 Page 278.3(f)	(a) (a)
22	**Gain/Loss on Reacquired Debt**	II.A.1.h	12,865,994	Plant	28.7026%	3,692,875	FF1 Page 111.81(c) + FF1 Page 113.61(c)	(a)
23	**Other Regulatory Assets**	II.A.1.i						
24	Unamortized Balance of Transmission Merger-Related Costs		$ -	Direct	100.0000%	-	**Exhibit No. ES-220, Page 2 of 8, Line 3(D)**	(b)
25	FAS 106 (182.3 & 254)		-	W&S	12.8871%	-	FF1 Page 232	(a)
26	ASC 740 (182.3 - FAS 109)		87,768,732				FF1 Page 232.29(f)	(a)
27	Less ASC 740 Liability (254 - FAS 109)		(4,015,556)				FF1 Page 278.1(f)	(a)
28	Net ASC 740 (182.3 & 254 - FAS 109)		83,753,176	Plant	28.7026%	24,039,339	Sum Lines 26 thru 27	(a)
29	Total Other Regulatory Assets		83,753,176			24,039,339	Line 25 + line 28	(b)
30	**Prepayments**	II.A.1.j	434,988,820	W&S	12.8871%	56,057,444	FF1 Page 111.57(c) + FF1 Page 232.1.2(f) +Page 232.1.3(f)	(a)
31	**Transmission Materials & Supplies**	II.A.1.k	28,541,503	Direct	100.0000%	28,541,503	FF1 Page 227.8(c) + FF1 Page 227.5(c) Footnote	(a)
32	**Cash Working Capital**	II.A.1.l						
33	Operation & Maintenance Expense		25,099,553	WC	12.5000%	3,137,444	Sheet 1a, Line 24, col (c)	(a)
34	Administrative & General Expense		23,434,949	WC	12.5000%	2,929,369	Sheet 1a, Line 25, col (c)	(c)
35	Transmission Support Expenses		3,811,865	WC	12.5000%	476,483	Sheet 1a, Line 28, col (c)	(a)
36	Total Cash Working Capital		52,346,367			6,543,296	Sum Lines 33 thru 35	(c)

Line	Description	Allocation Factor	Reference	Notes
37	Description	Factor	Reference	
38	Direct Allocation (Direct)	100.0000%		(a)
39	Wages & Salary (W&S)	12.8871%	Sheet 6, Line 6(c)	(a)
40	Plant Allocation (Plant)	28.7026%	Sheet 6, Line 14(c)	(a)
41	Construction Work in Progress Allocation (CWIP)	50.0000%	Sheet 6, Line 15(c)	(a)
42	Cash Working Capital (WC)	12.50%	Tariff Section II.A.1.l	(a)

43 **Note 1 -** Internal Records identify CWIP projects for rate base, as noted in the Exhibit "2014 Construction Work in Progress" included in this filing.

Notes:
(a) Source of information is the NSTAR Annual Informational Filing submitted to FERC on August 14, 2015 in Docket No. ER07-549 and ER09-1243.
(b) Proposed revisions reflect the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset
(c) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

NSTAR Electric Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-NSTAR Revenue Requirement Comparison Under Changed Rates
Under Attachment D
For Costs in 2014
Sheet 4

Line	(a) Description	(b) Tariff Section	(c) Total	(d) Allocator	(e) Factor	(f) Allocations LNS Amount	(g) Reference	(h) Notes
1	**Transmission Depreciation and Amortization Expense**	II.B						
2	Transmission Depreciation	II.B.i	$ 41,001,613	Direct	100.0000%	$ 41,001,613	FF1 Page 336.7(f)	(a)
3	General Plant Depreciation and Amortization	II.B.ii	8,991,113	W&S	12.8871%	1,158,694	FF1 Page 336.10(f)	(a)
4	Amortization of Transmission Related Intangible Plant		4,111,761	W&S	12.8871%	529,887	FF1 Page 336.1(f)	(a)
5	Amortization of AFUDC Regulatory Credit		(130,369)			(130,369)	FF1 Page 114.13(c)	(a)
6	Net Amortization of Transmission Related Intangible Plant		$ 3,981,392			$ 399,518	Sum Lines 4 and 5	(a)
7	Total Transmission Depreciation and Amortization Expense		$ 53,974,118			$ 42,559,825	Sum Lines 2, 3 and 6	(a)
8	**Amortization of Gain/Loss on Reacquired Debt**	II.C	$ 999,391	Plant	28.7026%	$ 286,851	FF1 Page 117.64(c) + FF1 Page 117.66(c)	(a)
9	**Transmission Related Amortization of ITC**	II.D	$ (1,310,106)	Plant	28.7026%	$ (376,034)	FF1 Page 114.19(c)	(a)
10	**Transmission Related Municipal Tax Expense**	II.E	$ 120,588,821	Plant	28.7026%	$ 34,612,127	FF1 Page 263.5(i)	(a)
11	**Transmission Related Payroll Tax Expense**	II.F	$ 12,412,619	W&S	12.8871%	$ 1,599,627	FF1 Page 263.10(i)	(a)
12	**Transmission Operation and Maintenance Expense**	II.G						
13	Operation Supervision & Engineering (560)		$ 5,674,265	Direct	100.0000%	5,674,265	FF1 Page 321.83(b)	(a)
14			-	Internal Costs		-	FF1 Page 321.84(b)	(a)
15	Load Dispatch - Reliability (561.1)		1,389,220	Internal Costs		1,389,220	FF1 Page 321.85(b)	(a)
16	Load Dispatch-Monitor and Operate Transmission System (561.2)		1,311,222	Internal Costs		1,311,222	FF1 Page 321.86(b)	(a)
17	Load Dispatch-Transmission Service and Scheduling (561.3)		570,681	Internal Costs		570,681	FF1 Page 321.87(b)	(a)
18	Scheduling, System Control and Dispatch Services (561.4)		12,155,295	External Costs		-	FF1 Page 321.88(b)	(a)
19	Reliability, Planning and Standards Development (561.5)		273,226	Internal Costs		21,719	FF1 Page 321.89(b)	(a)
20	Transmission Service Studies (561.6)		106	Internal Costs		106	FF1 Page 321.90(b)	(a)
21	Generation Interconnection Studies (561.7)		-	Internal Costs		-	FF1 Page 321.91(b)	(a)
22	Reliability, Planning and Standards Development Services (561.8)		53,935	External Costs		-	FF1 Page 321.92(b)	(a)
23	Station Expenses (562)		2,729,963	Direct	100.0000%	2,729,963	FF1 Page 321.93(b)	(a)
24	Overhead Lines Expenses (563)		4,327,839	Direct	100.0000%	4,327,839	FF1 Page 321.94(b)	(a)
25	Underground Lines Expenses (564)		636,122	Direct	100.0000%	636,122	FF1 Page 321.95(b)	(a)
26	Miscellaneous Transmission Expenses (566)		496,506	Direct	100.0000%	496,506	FF1 Page 321.97(b)	(a)
27	Rents (567)		14,755	Direct	100.0000%	14,755	Sheet 5 - Page 1 of 2, Line 3, col (d)	(a)
28	Transmission Maintenance (568 - 573)		7,927,155	Direct	100.0000%	7,927,155	FF1 Page 321.111(b)	(a)
29	Regional Market Expense (575-576)		424,648	External Costs	0.0000%	-	FF1 Page 322.131(b)	(a)
30	Total Transmission O&M Expense		$ 37,984,938			$ 25,099,553	Sum Lines 13 thru 29	(a)
31	**Transmission Related A&G Expenses**	II.H						
32	Administrative and General Expenses	I.B	$ 145,329,829				FF1 Page 323.197(b)	(a)
33	Property Insurance (924)		(926,016)				FF1 Page 323.185(b)	(a)
34	Employee Pensions and Benefits (926)		(51,124,252)				FF1 Page 323.187(b)	(a)
35	Regulatory Commission Expenses (928)		(9,560,209)				FF1 Page 323.189(b)	(a)
36	General Advertising Expenses (930.1)		(32,018)				FF1 Page 323.191(b)	(a)
37	Miscellaneous General Expenses (930.2) - **Note 2**		(52,118)				FF1 Page 232.2.14(e)	(a)
38	Merger-Related Costs		-				FF1 Page 232.2.14(e)	(b)
39	Sub-Total	II.H.1	83,635,216	W&S	12.8871%	10,778,154	Sum Lines 32 thru 38	(b)
40	Property Insurance (924)	II.H.2	926,016	Plant	28.7026%	265,791	Line 33	(a)
41	Employee Pensions and Benefits (926) - **Note 1**	II.H.1	51,124,252	W&S	12.8871%	6,588,433	Line 34	(a)
42	Regulatory Commission Expenses (928)	II.H.3	9,560,209	Footnote	20.8403%	1,992,376	Line 50	(a)
43	Transmission Merger-Related Costs		3,810,195	Footnote	100.0000%	3,810,195	**Exhibit No. ES-220, Page 2 of 8, Line 2(D)**	(b)
44	Total Transmission Related A&G Expenses		$ 149,055,888			$ 23,434,949	Sum Lines 39 thru 42	(b)
45	Regulatory Commission Expenses (928)	II.H.3						(a)
46	Assessment Charged by the MA DPU		$ 6,712,589		0.0000%	$ -	FF1 Page 350.2(d)	(a)
47	Proportionate share of expenses of FERC Assessment Order No. 472		1,992,376	Direct	100.0000%	1,992,376	FF1 Page 350.6(d)	(a)
48	Legal Fees - Distribution		787,573		0.0000%	-	FF1 Page 350.8(d)	(a)
49	Minor items - Distribution		67,671		0.0000%	-	FF1 Page 350.10(d)	(a)
50	Total Regulatory Commission Expenses	II.H.3	$ 9,560,209		20.8403%	$ 1,992,376	Sum Lines 46 thru 49	(a)

Line	Description	Allocation Factor	Reference	Notes
51				
52	Direct Allocation (Direct)	100.0000%		(a)
53	Wages & Salaries Allocation (W&S)	12.8871%	Sheet 6, Line 6(c)	(a)
54	Plant Allocation (Plant)	28.7026%	Sheet 6, Line 14(c)	(a)

55 **Note 1**
56 Included in the Employee Pension and Benefits Expenses are costs related to Post Retirement Benefits other than Pension (PBOP). PBOP costs are determined by an independent actuary
57 as required by ASC 715. The PBOP expense included in Account 926 for 2014 was ($5,000,000) as compared to $4,600,000 in 2013; as shown on the FF1, page 323, footnote.
58 Applying the labor allocator to the total PBOP expense results in $(251,041) of PBOP expense being recovered through the LNS Tariff in 2014, as compared to $249,762 in the prior year.

Line		2014	2013		Notes
59	PBOP	$ (5,000,000)	$ 4,600,000	Page 323 line 187 footnote	(a)
60	Capitalized PBOP & Other impact adjustment	3,052,000	(1,866,000)	**Note 3**	(a)
61	Net PBOP in account 926	$ (1,948,000)	$ 2,734,000	Line 57 + Line 58	(a)
62	Wages & Salaries Allocation (W&S)	12.8871%	9.1354%	Sheet 6	(a)
63	LNS portion of PBOP	$ (251,041)	$ 249,762	Line 59 x Line 60	(a)

64 **Note 2 -** NSTAR Green Program costs are excludable for Transmission billing purposes. Reflects actual information per Eversource's accounting records.
65 **Note 3** - Reflects actual information per Eversource's accounting records. ;

Notes:
(a) Source of information is the NSTAR Annual Informational Filing submitted to FERC on August 14, 2015 in Docket No. ER07-549 and ER09-1243.
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Exhibit No. ES-226
Schedule 1

Summary of Impact on Category B Revenue Requirements under Attachment ES-I, Schedule 21-ES to ISO-NE OATT (3-year amortization)

Eversource Energy Service Company

Eversource Energy Service Company
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirement Comparison Under Present and Changed Rates
Under Attachment ES-I (Formerly NU-I)
For the Calendar Years 2016-2018

Line	(A) Description	(B) Total Category B Revenue Requirements Present Rates in Attachment ES-I		(C) Total Category B Revenue Requirements under Changed Rates in Attachment ES-I		(D) = (C) - (B) Difference (5) (Rounded to '000s)	(E) = (D) / (B) % Difference
1	2016 Estimated Category B Revenue Requirement	$ 35,511,216	(1)	$ 36,033,724	(2)	$ 523,000	1.5%
2	2017 Estimated Category B Revenue Requirement	$ 35,511,216	(1)	$ 36,066,352	(3)	$ 555,000	1.6%
3	2018 Estimated Category B Revenue Requirement	$ 35,511,216	(1)	$ 36,009,732	(4)	$ 499,000	1.4%

Notes:
(1) Exhbit No. ES-226, Schedule 2, Page 1 of 26, Line 9(H)
(2) Exhbit No. ES-226, Schedule 3, Page 1 of 26, Line 9(H)
(3) Exhbit No. ES-226, Schedule 4, Page 1 of 26, Line 9(H)
(4) Exhbit No. ES-226, Schedule 5, Page 1 of 26, Line 9(H)
(5) In connection with the three-year amortization alternative (with the proposed effective date of June 1, 2016), Eversource is showing the revenue impact for the thirty-six month period June 1, 2016 through May 31, 2019. Eversource is using calendar year revenue requirement calculations as estimates for the thirty-six month period beginning June 1, 2016. See Cooper Testimony Exhibit No. ES-200.

	2016	2017	2018	2019	Total
The amounts for each year are as follows:	$ 305,000	$ 542,000	$ 522,000	$ 208,000	$ 1,577,000

Exhibit No. ES-226
Schedule 2

Category B Revenue Requirements under the Present Rates

Eversource Energy Service Company

CL&P and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I) of the ISO-NE OATT
For the Calendar years 2016-2018

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)=(C)+(D)+(E)+(F)+(G)
			CL&P				WMECO	
Line	Description	Reference	B-N	M-N	G-C	GSRP	GSRP	Total
1	2014 Actual Schedule 21-ES, Category B Rev. Req.		$ 19,230,913 (1)	$ 10,169,321 (2)	$ 4,297,973 (3)	$ 579,688 (4)	$ 1,233,321 (5)	$ 35,511,216
2	Estimated 2015 Plant Additions	(6)	$ -	$ -	$ -	$ -	$ -	$ -
3	Carrying Charge Factor (CCF)	(6)	0.00%	0.00%	0.00%	0.00%	0.00%	
4	2015 Incremental Estimated Schedule 21-ES, Cat. B Rev. Req.	Line 2 x 3	-	-	-	-	-	$ -
5	Total Estimated Schedule 21-ES, Cat. B Revenue Requirement for 2015	Line 1 + 4	$ 19,230,913	$ 10,169,321	$ 4,297,973	$ 579,688	$ 1,233,321	$ 35,511,216
6	Estimated 2016 Plant Additions	(6)	$ -	$ -	$ -	$ -	$ -	$ -
7	Carrying Charge Factor (CCF)	(6)	0.00%	0.00%	0.00%	0.00%	0.00%	
8	2016 Incremental Estimated Schedule 21-ES, Cat. B Rev. Req.	Line 7 x 8	-	-	-	-	-	$ -
9	Total Estimated Schedule 21-ES, Cat. B Revenue Requirement for 2016	Line 6 + 9	$ 19,230,913	$ 10,169,321	$ 4,297,973	$ 579,688	$ 1,233,321	$ 35,511,216 (7)

Notes:
(1) Exhibit No. ES-226, Schedule 2, Page 2 of 26, Line 21(B)
(2) Exhibit No. ES-226, Schedule 2, Page 7 of 26, Line 21(B)
(3) Exhibit No. ES-226, Schedule 2, Page 12 of 26, Line 21(B)
(4) Exhibit No. ES-226, Schedule 2, Page 17 of 26, Line 21(B)
(5) Exhibit No. ES-226, Schedule 2, Page 22 of 26, Line 21(B)
(6) These are no forecasted plant additions for Category B
(7) The revenue requirements calculations for the calendar year 2016 (including any forecast for 2016) are used as an estimate for the revenue requirements for 2017 and 2018, which are used to calculate the revenue impact of the proposed cost recovery.

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Bethel-Norwalk
Sheet 1a

Line	(A)	Attachment I Reference Section:	(B)	(C) Source	(D) Notes
	I. INVESTMENT BASE				
1	Transmission Plant	II(A)(1)(a)	125,258,704	Sheet 2, Line 5	(a)
2	Transmission Plant Held for Future Use	II(A)(1)(b)	-	Sheet 2, Line 6	(a)
3	Accumulated Depreciation	II(A)(1)(c)	23,816,817	Sheet 2, Line 11	(a)
4	Accumulated Deferred Income Taxes	II(A)(1)(d)	19,494,337	Sheet 2, Line 12	(a)
5	Loss On Reacquired Debt	II(A)(1)(e)	187,920	Sheet 2, Line 13	(a)
6	Net Investment (Line 1+2-3-4+5)		82,135,470		
7	Prepayments	II(A)(1)(f)	787,415	Sheet 2, Line 14	(a)
8	Materials & Supplies	II(A)(1)(g)	1,459,628	Sheet 2, Line 15	(a)
9	Cash Working Capital	II(A)(1)(h)	381,388	Sheet 2, Line 22	(b)
10	Total Investment Base (Line 6+7+8+9)		84,763,901		(b)
	II. REVENUE REQUIREMENTS				
11	Investment Return and Income Taxes	II(A)	10,946,427	Sheet 4a, Line 15(4)	(b)
12	Depreciation Expense	II(B)	3,051,146	Sheet 8, Line 5	(a)
13	Amortization of Loss on Reacquired Debt	II(C)	19,538	Sheet 8, Line 6	(a)
14	Investment Tax Credit	II(D)	(22,551)	Sheet 8, Line 7	(a)
15	Property Tax Expense	II(E)	1,802,271	Sheet 8, Line 8	(a)
16	Payroll Tax Expense	II(F)	13,032	Sheet 8, Line 21	(a)
17	Operation & Maintenance Expense	II(G)	1,529,404	Sheet 8, Line 29	(a)
18	Administrative & General Expense	II(H)	1,493,448	Sheet 8, Line 39	(b)
19	Support Expenses	II(I)	-		(a)
20	Transmission Related Taxes and Fees	II(J)	398,198	Sheet 8, Line 40	(a)
21	Total Revenue Requirements (Line 11 thru 20)		19,230,913		(b)

Note:
Investment Return and Income Taxes (line 11 above) was calculated based on the Total Investment Base at 11.07% ROE, plus the Localized Post-2003 PTF Transmission Base (lines 1-3-4) at the .67% capped Incremental ROE.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247. Provided this support because these balances will be revised under the changed rates.

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Bethel-Norwalk
Sheet 2

Line No.	(A)	(B) Trans. Related Average		(C) Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Transmission Plant							
1	Localized Transmission Plant					121,745,648	Sheet 3, Line 19	(a)
2	Transmission General Plant	102,812,641	Note 4				FF1 page 204 ln. 96, footnote	(a)
3	Less: Convex-related General Plant	15,870,872					Note 1	(a)
4	Subtotal: General Plant, net of Convex (line 2 - 3)	86,941,769		4.0407%	Note 2	3,513,056		(a)
5	Total (line 1+4)					125,258,704		(a)
6	Localized Transmission Plant Held for Future Use					-		(a)
	Transmission Accumulated Depreciation							
7	Localized Transmission Accum. Depreciation					22,912,990	Sheet 9, Line 56(I)	(a)
8	General Plant Accum. Depreciation	26,085,325	Note 4				FF1 page 219 ln. 28, footnote	(a)
9	Less: Convex-related General Plant Acc Depr	3,717,252					Note 1	(a)
10	Subtotal: General Plant A/D, net of Convex (line 8-9)	22,368,074		4.0407%	Note 2	903,827		(a)
11	Total (line 7+10)					23,816,817		(a)
12	Transmission Accumulated Deferred Taxes					19,494,337	Sheet 10, Line 111	(a)
13	Unam. Loss on Reacquired Debt (189)	12,599,425		1.4915%	Note 3	187,920	FF1 page 111 ln. 81	(a)
14	Transmission Prepayments (165)	19,487,085	Note 4	4.0407%	Note 2	787,415	FF1 page 110 ln. 57, footnote	(a)
15	Transmission Materials and Supplies	36,123,136		4.0407%	Note 2	1,459,628	FF1 page 227 ln. 8	(a)
	Cash Working Capital							
16	Localized Operation & Maintenance Expense					1,529,404	Sheet 8, Line 29	(a)
17	Localized Administrative & General Expense					1,493,448	Sheet 8, Line 39	(b)
18	Subtotal (line 16+17)					3,022,852		(b)
19	12.5% allowance					0.125	x 45 / 360	(a)
20	Total current Year End (line 18*19)					377,857		(b)
21	Prior Year End Cash Working Capital					384,919	Note 1	(a)
22	Average Cash Working Capital [(line 20+21)/2]					381,388		(b)

Note 1: Reflects actual information per Eversource's accounting records.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247 Provided this support because these balances will be revised under the changed rates.

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Bethel-Norwalk
Sheet 4a

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559	Note 2	46.27%	5.36%	Note 2	2.48%		
2	PREFERRED STOCK	$ 116,842,775		2.14%	4.80%		0.10%	0.10%	
3	COMMON EQUITY	$ 2,820,159,065		51.59%	11.07%	Note 1	5.71%	5.71%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399		100.00%			8.29%	5.81%	

Cost of Capital Rate=

Line										
5	(a) Weighted Cost of Capital	=	8.29% Line 4, Col. (4)							
	(b) Federal Income Tax	= ((	R.O.E.	+ ((	Total Inv. (Tax Credit)	+	Eq. AFUDC of Deprec. Exp.	) /	Total Inv. Base	)) * Federal Income Tax Rate)
				(	1	-	Federal Income Tax Rate	)		
		Source:	Line 4, Col. (5)		Sheet 8, Line 7		Sheet 6, Line 1		Sheet 1, Line 10	Federal Corporate Tax Rate
6		= ((	5.81%	+ ((	(22,551)	+	93,235	) /	84,763,901	)) * 35.00%)
7				(	1	-	35.00%	)		
							Federal Corporate Tax Rate			
8		=	3.1734%							
	(c) State Income Tax	= ((	R.O.E.	+ ((	Total Inv. (Tax Credit)	+	Eq. AFUDC of Deprec. Exp.	) /	Total Inv. Base	) + Federal Income Tax) * State Income Tax Rate)
				(	1	-	State Income Tax Rate	)		
		Source:	Line 4, Col. (5)		Sheet 8, Line 7		Sheet 6, Line 1		Sheet 1, Line 10	Line 8, Col. (1); Connecticut Corporate Tax Rate
9		= ((	5.81%	+ ((	(22,551)	+	93,235	) /	84,763,901	) + 3.1734%) * 9.00%)
10				(	1	-	9.00%	)		
							Connecticut Corporate Tax Rate			
11		=	0.8967%							
12	(a)+(b)+(c) **Cost of Capital Rate**	=	12.3601%							

Line			
13	INVESTMENT BASE	84,763,901	Sheet 1, Line 10
14			
15	x Cost of Capital Rate	12.3601%	Line 12, Col. (1)
16	= Investment Return and Income Taxes	$ 10,476,903	

Total Investment Return and Income Taxes		
@11.07%	$ 10,476,903	Line 16, Col. (1)
@.67%	$ 469,524	Sheet 5a, Line 17
	$ 10,946,427	To Sheet 1a, Line 11

Note 1: ROE per FERC Order in Docket No. ER11-66 dated October 16, 2014.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes:

(1) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(2) Provided this support because the balance in "Total Inv. Base" will be revised under the Changed Rates

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Bethel-Norwalk

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559	Note 2	46.27%					
2	PREFERRED STOCK	$ 116,842,775		2.14%					
3	COMMON EQUITY	$ 2,820,159,065		51.59%	0.50%	Note 1	0.26%	0.26%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399		100.00%			0.26%	0.26%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.26% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate)) / Total Inv. Base)) * Federal Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Federal Corporate Tax Rate

6 = ((0.26% + ((0 + 0) / Line 16, Col. (4) 84,763,901)) * 35.00%)
7 (1 - 35.00%) Federal Corporate Tax Rate

8 = 0.1400%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate)) / Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Line 8, Col. (1); Connecticut Corporate Tax Rate

9 = ((0.26% + ((0 + 0) / 84,763,901) + 0.1400%) * 9.00%)
10 (1 - 9.00%) Connecticut Corporate Tax Rate

11 = 0.0396%

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.4396%

13	INVESTMENT BASE	84,763,901	Line 16, Col. (4)
14	x Cost of Capital Rate	0.4396%	Line 12, Col. (1)
15	= Investment Return and Income Taxes	$ 372,622	to Sheet 4a, Line 14(4)

Note 1: CAP on ROE incentives per FERC Order in Docket No. EL11-66 dated March 3, 2015.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.

Notes:

(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-217, Schedule 2, Line 8
(2) The balance in "Total Inv. Base" is revised under the Changed Rates

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Bethel-Norwalk
Sheet 8

Line No.	(A)	(B) Year End		(C) Localized Trans. Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Depreciation Expense							
1	Transmission Depreciation					2,894,776	Sheet 9, Line 58	(a)
2	General Depreciation	4,980,574	Note 4				FF1 page 336 ln. 10, footnote	(a)
3	*less:* Convex-related General Plant Depreciation Expense	1,110,693					Note 1	(a)
4	Subtotal: General Plant Depr Exp, net of Convex (line 2-3)	3,869,881		4.0407%	Note 2	156,370		(a)
5	Total (line 1+4)					3,051,146		(a)
6	Amortization of Loss on Reacquired Debt	1,309,927		1.4915%	Note 3	19,538	FF1 page 117 ln. 64	(a)
7	Amortization of Investment Tax Credits	1,511,975		1.4915%	Note 3	22,551	FF1 page 266 ln. 8 (f)	(a)
8	Property Taxes	120,836,131		1.4915%	Note 3	1,802,271	FF1 page 263 ln. 24i & 25i	(a)
	Payroll Tax Expense							
9	Federal Unemployment	5,226					FF1 page 262 ln. 3i, footnote	(a)
10	FICA	233,351					FF1 page 262 ln. 5i, footnote	(a)
11	Medicare	65,613					FF1 page 262 ln. 9i, footnote	(a)
12	CT Unemployment	16,786					FF1 page 262 ln. 15i, footnote	(a)
13	MA Unemployment	(285)					FF1 page 262 ln. 32i, footnote	(a)
14	MA Universal Health	64					FF1 page 262 ln. 33i, footnote	(a)
15	NH Unemployment	1,754					FF1 page 262.1 ln. 4i, footnote	(a)
16	NJ Unemployment	-					FF1 page 262 footnote	(a)
17	DC Unemployment	11					FF1 page 262.1 ln. 14i, footnote	(a)
18	FL Unemployment	1					FF1 page 262.1 ln. 18i, footnote	(a)
19	MI Unemployment	6					FF1 page 262.1 ln. 22i, footnote	(a)
20	NY Unemployment	-					FF1 page 262.1 ln. 10i, footnote	(a)
21	Total (Line 9 to 20)	322,527	Note 4	4.0407%	Note 2	13,032		
	Transmission Operation and Maintenance							
22	Operation and Maintenance	77,432,007					FF1 page 321 ln. 112	(a)
23	Transmission of Electricity by Others - #565	21,727,966					FF1 page 321 ln. 96	(a)
24	Load Dispatching - #561	-					FF1 page 321 ln. 84	(a)
25	Account 561.1	3,245,594					FF1 page 321 ln. 85	(a)
26	Account 561.2	5,212,556					FF1 page 321 ln. 86	(a)
27	Account 561.3	2,238,612					FF1 page 321 ln. 87	(a)
28	Account 561.4	7,157,291					FF1 page 321 ln. 88	(a)
29	O&M (line 22 - lines 23 to 28)	37,849,988		4.0407%	Note 2	1,529,404		(a)
	Transmission-related Administrative and General							
30	Administrative and General	37,202,294	Note 4				FF1 page 320 ln. 197 b, footnote	(a)
31	less: Property Insurance (#924)	763,857	Note 4				FF1 Page 320 ln. 185 b, footnote	(a)
32	less: Regulatory Commission Expenses (#928)	2,749,411	Note 4				FF1 page 320 ln. 189 b, footnote	(a)
33	less: General Advertising Expense (#930.1)	10,766	Note 4				FF1 page 320 ln. 191 b, footnote	(a)
34	Subtotal (line 30 - lines 31 to 33)	33,678,260		4.0407%	Note 2	1,360,837		(a)
35	plus: Property Insurance	1,413,419		1.4915%	Note 3	21,081	FF1 page 323 ln. 185	(a)
36	plus: Trans. Regulatory Comm. Exp.	2,749,411		4.0407%	Note 2	111,095	FF1 page 320 ln. 189 b, footnote	(a)
37	plus: Trans. Related General Advertising Expense	10,766		4.0407%	Note 2	435	FF1 page 320 ln. 191 b, footnote	(a)
38	plus: Trans. Related Public Education Expense	-				-	FF1 page 114 ln. 49, footnote	(a)
39	Total A&G (sum of lines 34 to 38)	37,851,856				1,493,448		(b)
40	Transmission Related Taxes and Fees	9,854,673		4.0407%	Note 2	398,198	Note 5	(a)

Note 1: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.
Note 5: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment B.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247 Provided this support because these balances will be revised under the changed rates.

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Middletown-Norwalk
Sheet 1a

Line	(A)	Attachment I Reference Section:	(B)	(C) Source	(D) Notes
	I. INVESTMENT BASE				
1	Transmission Plant	II(A)(1)(a)	62,028,638	Sheet 2, Line 5	(a)
2	Transmission Plant Held for Future Use	II(A)(1)(b)	-	Sheet 2, Line 6	(a)
3	Accumulated Depreciation	II(A)(1)(c)	9,382,562	Sheet 2, Line 11	(a)
4	Accumulated Deferred Income Taxes	II(A)(1)(d)	7,626,580	Sheet 2, Line 12	(a)
5	Loss On Reacquired Debt	II(A)(1)(e)	93,059	Sheet 2, Line 13	(a)
6	Net Investment (Line 1+2-3-4+5)		45,112,555		
7	Prepayments	II(A)(1)(f)	389,937	Sheet 2, Line 14	(a)
8	Materials & Supplies	II(A)(1)(g)	722,824	Sheet 2, Line 15	(a)
9	Cash Working Capital	II(A)(1)(h)	188,956	Sheet 2, Line 22	(b)
10	Total Investment Base (Line 6+7+8+9)		46,414,272		(b)
	II. REVENUE REQUIREMENTS				
11	Investment Return and Income Taxes	II(A)	5,993,077	Sheet 4a, Line 15(4)	(b)
12	Depreciation Expense	II(B)	1,584,643	Sheet 8, Line 5	(a)
13	Amortization of Loss on Reacquired Debt	II(C)	9,675	Sheet 8, Line 6	(a)
14	Investment Tax Credit	II(D)	(11,167)	Sheet 8, Line 7	(a)
15	Property Tax Expense	II(E)	892,496	Sheet 8, Line 8	(a)
16	Payroll Tax Expense	II(F)	6,454	Sheet 8, Line 21	(a)
17	Operation & Maintenance Expense	II(G)	757,378	Sheet 8, Line 29	(a)
18	Administrative & General Expense	II(H)	739,573	Sheet 8, Line 39	(b)
19	Support Expenses	II(I)	-		(a)
20	Transmission Related Taxes and Fees	II(J)	197,192	Sheet 8, Line 40	(a)
21	Total Revenue Requirements (Line 11 thru 20)		10,169,321		(b)

Note:
Investment Return and Income Taxes (line 11 above) was calculated based on the Total Investment Base at 11.07% ROE, plus the Localized Post-2003 PTF Transmission Base (lines 1-3-4) at the .67% capped Incremental ROE.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247. Provided this support because these balances will be revised under the changed rates.

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Middletown-Norwalk
Sheet 2

Line No.	(A)	(B) Trans. Related Average		(C) Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Transmission Plant							
1	Localized Transmission Plant					60,288,933	Sheet 3, Line 18	(a)
2	Transmission General Plant	102,812,641	Note 4				FF1 page 204 ln. 96, footnote	(a)
3	Less: Convex-related General Plant	15,870,872					Note 1	(a)
4	Subtotal: General Plant, net of Convex (line 2 - 3)	86,941,769		2.0010%	Note 2	1,739,705		(a)
5	Total (line 1+4)					62,028,638		(a)
6	Localized Transmission Plant Held for Future Use					-		(a)
	Transmission Accumulated Depreciation							
7	Localized Transmission Accum. Depreciation					8,934,977	Sheet 9, Line 84(I)	(a)
8	General Plant Accum. Depreciation	26,085,325	Note 4				FF1 page 219 ln. 28, footnote	(a)
9	Less: Convex-related General Plant Acc Depr	3,717,252					Note 1	(a)
10	Subtotal: General Plant A/D, net of Convex (line 8-9)	22,368,074		2.0010%	Note 2	447,585		(a)
11	Total (line 7+10)					9,382,562		(a)
12	Transmission Accumulated Deferred Taxes					7,626,580	Sheet 10, Line 105	(a)
13	Unam. Loss on Reacquired Debt (189)	12,599,425		0.7386%	Note 3	93,059	FF1 page 111 ln. 81	(a)
14	Transmission Prepayments (165)	19,487,085	Note 4	2.0010%	Note 2	389,937	FF1 page 110 ln. 57, footnote	(a)
15	Transmission Materials and Supplies	36,123,136		2.0010%	Note 2	722,824	FF1 page 227 ln. 8	(a)
	Cash Working Capital							
16	Localized Operation & Maintenance Expense					757,378	Sheet 8, Line 29	(a)
17	Localized Administrative & General Expense					739,573	Sheet 8, Line 39	(b)
18	Subtotal (line 16+17)					1,496,951		(b)
19	12.5% allowance					0.125	x 45 / 360	(a)
20	Total current Year End (line 18*19)					187,119		(b)
21	Prior Year End Cash Working Capital					190,793	Note 1	(a)
22	Average Cash Working Capital [(line 20+21)/2]					188,956		(b)

Note 1: Reflects actual information per Eversource's accounting records.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
Provided this support because these balances will be revised under the changed rates.

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Middletown-Norwalk
Sheet 4a

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559	Note 2	46.27%	5.36%	Note 2	2.48%		
2	PREFERRED STOCK	$ 116,842,775		2.14%	4.80%		0.10%	0.10%	
3	COMMON EQUITY	$ 2,820,159,065		51.59%	11.07%	Note 1	5.71%	5.71%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399		100.00%			8.29%	5.81%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 8.29% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate) Total Inv. Base)) * Federal Income Tax Rate)

Source: Line 4, Col. (5); Sheet 8, Line 7; Sheet 6, Line 1; Sheet 1, Line 10; Federal Corporate Tax Rate

6 = ((5.81% + (((11,167) + 46,171) / 46,414,272)) * 35.00%)
7 (1 - 35.00%) Federal Corporate Tax Rate

8 = 3.1691%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate) Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)

Source: Line 4, Col. (5); Sheet 8, Line 7; Sheet 6, Line 1; Sheet 1, Line 10; Line 8, Col. (1); Connecticut Corporate Tax Rate

9 = ((5.81% + (((11,167) + 46,171) / 46,414,272) + 3.1691%) * 9.00%)
10 (1 - 9.00%) Connecticut Corporate Tax Rate

11 = 0.8955%

12 (a)+(b)+(c) **Cost of Capital Rate** = 12.3546%

13	INVESTMENT BASE	46,414,272	Sheet 1, Line 10
14			
15	x Cost of Capital Rate	12.3546%	Line 12, Col. (1)
16	= Investment Return and Income Taxes	$ 5,734,298	

Total Investment Return and Income Taxes		
@11.07%	$ 5,734,298	Line 16, Col. (1)
@.67%	$ 258,779	Sheet 5a, Line 17
	$ 5,993,077	To Sheet 1a, Line 11

Note 1: ROE per FERC Order in Docket No. ER11-66 dated October 16, 2014.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes:

(1) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(2) Provided this support because the balance in "Total Inv. Base" will be revised under the Changed Rates

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Middletown-Norwalk
Sheet 5a

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559	Note 2	46.27%					
2	PREFERRED STOCK	$ 116,842,775		2.14%					
3	COMMON EQUITY	$ 2,820,159,065		51.59%	0.50%	Note 1	0.26%	0.26%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399		100.00%			0.26%	0.26%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.26% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate)) / Total Inv. Base)) * Federal Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Federal Corporate Tax Rate

6 = ((0.26% + ((0 + 0) / Line 16, Col. (4) 46,414,272)) * 35.00%)
7 (1 - 35.00% Federal Corporate Tax Rate)

8 = 0.1400%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate)) / Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Line 8, Col. (1); Connecticut Corporate Tax Rate

9 = ((0.26% + ((0 + 0) / 46,414,272) + 0.1400%) * 9.00%)
10 (1 - 9.00% Connecticut Corporate Tax Rate)

11 = 0.0396%

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.4396%

13 INVESTMENT BASE 46,414,272 Line 16, Col. (4)

14 x Cost of Capital Rate 0.4396% Line 12, Col. (1)

15 = Investment Return and Income Taxes $ 204,037 to Sheet 4a, Line 14(4)

Note 1: CAP on ROE incentives per FERC Order in Docket No. EL11-66 dated March 3, 2015.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.

Notes:

(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-217, Schedule 2, Line 8
(2) The balance in "Total Inv. Base" is revised under the Changed Rates

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Middletown-Norwalk
Sheet 8

Line No.	(A)	(B) Year End		(C) Localized Trans. Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Depreciation Expense							
1	Transmission Depreciation					1,507,207	Sheet 9, Line 86	(a)
2	General Depreciation	4,980,574	Note 4				FF1 page 336 ln. 10, footnote	(a)
3	*less:* Convex-related General Plant Depreciation Expense	1,110,693					Note 1	(a)
4	Subtotal: General Plant Depr Exp, net of Convex (line 2-3)	3,869,881		2.0010%	Note 2	77,436		(a)
5	Total (line 1+4)					1,584,643		(a)
6	Amortization of Loss on Reacquired Debt	1,309,927		0.7386%	Note 3	9,675	FF1 page 117 ln. 64	(a)
7	Amortization of Investment Tax Credits	1,511,975		0.7386%	Note 3	11,167	FF1 page 266 ln. 8 (f)	(a)
8	Property Taxes	120,836,131		0.7386%	Note 3	892,496	FF1 page 263 ln. 24i & 25i	(a)
	Payroll Tax Expense							
9	Federal Unemployment	5,226					FF1 page 262 ln. 3i, footnote	(a)
10	FICA	233,351					FF1 page 262 ln. 5i, footnote	(a)
11	Medicare	65,613					FF1 page 262 ln. 9i, footnote	(a)
12	CT Unemployment	16,786					FF1 page 262 ln. 15i, footnote	(a)
13	MA Unemployment	(285)					FF1 page 262 ln. 32i, footnote	(a)
14	MA Universal Health	64					FF1 page 262 ln. 33i, footnote	(a)
15	NH Unemployment	1,754					FF1 page 262.1 ln. 4i, footnote	(a)
16	NJ Unemployment	-					FF1 page 262 footnote	(a)
17	DC Unemployment	11					FF1 page 262.1 ln. 14i, footnote	(a)
18	FL Unemployment	1					FF1 page 262.1 ln. 18i, footnote	(a)
19	MI Unemployment	6					FF1 page 262.1 ln. 22i, footnote	(a)
20	NY Unemployment	-					FF1 page 262.1 ln. 10i, footnote	(a)
21	Total (Line 9 to 20)	322,527	Note 4	2.0010%	Note 2	6,454		(a)
	Transmission Operation and Maintenance							
22	Operation and Maintenance	77,432,007					FF1 page 321 ln. 112	(a)
23	Transmission of Electricity by Others - #565	21,727,966					FF1 page 321 ln. 96	(a)
24	Load Dispatching - #561	-					FF1 page 321 ln. 84	(a)
25	Account 561.1	3,245,594					FF1 page 321 ln. 85	(a)
26	Account 561.2	5,212,556					FF1 page 321 ln. 86	(a)
27	Account 561.3	2,238,612					FF1 page 321 ln. 87	(a)
28	Account 561.4	7,157,291					FF1 page 321 ln. 88	(a)
29	O&M (line 22 - lines 23 to 28)	37,849,988		2.0010%	Note 2	757,378		(a)
	Transmission-related Administrative and General							
30	Administrative and General	37,202,294	Note 4				FF1 page 320 ln. 197 b, footnote	(a)
31	less: Property Insurance (#924)	763,857	Note 4				FF1 Page 320 ln. 185 b, footnote	(a)
32	less: Regulatory Commission Expenses (#928)	2,749,411	Note 4				FF1 page 320 ln. 189 b, footnote	(a)
33	less: General Advertising Expense (#930.1)	10,766	Note 4				FF1 page 320 ln. 191 b, footnote	(a)
34	Subtotal (line 30 - lines 31 to 33)	33,678,260		2.0010%	Note 2	673,902		(a)
35	plus: Property Insurance	1,413,419		0.7386%	Note 3	10,440	FF1 page 323 ln. 185	(a)
36	plus: Trans. Regulatory Comm. Exp.	2,749,411		2.0010%	Note 2	55,016	FF1 page 320 ln. 189 b, footnote	(a)
37	plus: Trans. Related General Advertising Expense	10,766		2.0010%	Note 2	215	FF1 page 320 ln. 191 b, footnote	(a)
38	plus: Trans. Related Public Education Expense	-				-	FF1 page 114 ln. 49, footnote	(a)
39	Total A&G (sum of lines 34 to 38)	37,851,856				739,573		(b)
40	Transmission Related Taxes and Fees	9,854,673		2.0010%	Note 2	197,192	Note 5	(a)

Note 1: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.
Note 5: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment B.

Notes:

(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247 Provided this support because these balances will be revised under the changed rates.

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Glenbrook Cables
Sheet 1a

Line	(A) I. INVESTMENT BASE	Attachment I Reference Section:	(B)	(C) Source	(D) Notes
1	Transmission Plant	II(A)(1)(a)	2,644,161	Sheet 2, Line 5	(a)
2	Transmission Plant Held for Future Use	II(A)(1)(b)	31,396,972	Sheet 2, Line 6	(a)
3	Accumulated Depreciation	II(A)(1)(c)	353,497	Sheet 2, Line 11	(a)
4	Accumulated Deferred Income Taxes	II(A)(1)(d)	323,209	Sheet 2, Line 12	(a)
5	Loss On Reacquired Debt	II(A)(1)(e)	3,969	Sheet 2, Line 13	(a)
6	Net Investment (Line 1+2-3-4+5)		33,368,396		
7	Prepayments	II(A)(1)(f)	16,622	Sheet 2, Line 14	(a)
8	Materials & Supplies	II(A)(1)(g)	30,813	Sheet 2, Line 15	(a)
9	Cash Working Capital	II(A)(1)(h)	8,056	Sheet 2, Line 22	(b)
10	Total Investment Base (Line 6+7+8+9)		33,423,887		(b)
	II. REVENUE REQUIREMENTS				
11	Investment Return and Income Taxes	II(A)	4,124,327	Sheet 4a, Line 15(4)	(b)
12	Depreciation Expense	II(B)	63,152	Sheet 8, Line 5	(a)
13	Amortization of Loss on Reacquired Debt	II(C)	413	Sheet 8, Line 6	(a)
14	Investment Tax Credit	II(D)	(476)	Sheet 8, Line 7	(a)
15	Property Tax Expense	II(E)	38,063	Sheet 8, Line 8	(a)
16	Payroll Tax Expense	II(F)	275	Sheet 8, Line 21	(a)
17	Operation & Maintenance Expense	II(G)	32,286	Sheet 8, Line 29	(a)
18	Administrative & General Expense	II(H)	31,527	Sheet 8, Line 39	(b)
19	Support Expenses	II(I)	-		(a)
20	Transmission Related Taxes and Fees	II(J)	8,406	Sheet 8, Line 40	(a)
21	Total Revenue Requirements (Line 11 thru 20)		4,297,973		(b)

Note:
Investment Return and Income Taxes (line 11 above) was calculated based on the Total Investment Base at 11.07% ROE, plus the Localized Post-2003 PTF Transmission Base (lines 1-3-4) at the .67% capped Incremental ROE.

Notes:

(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247

(b) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247. Provided this support because these balances will be revised under the changed rates.

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Glenbrook Cables
Sheet 2

Line No.	(A)	(B) Trans. Related Average		(C) Allocation Factor	(D) Allocated to Localized	(E) Source	(F) Notes
	Transmission Plant						
1	Localized Transmission Plant				2,570,000	Sheet 3, Line 17	(a)
2	Transmission General Plant	102,812,641	Note 4			FF1 page 204 ln. 96, footnote	(a)
3	Less: Convex-related General Plant	15,870,872				Note 1	(a)
4	Subtotal: General Plant, net of Convex (line 2 - 3)	86,941,769		0.0853% Note 2	74,161		(a)
5	Total (line 1+4)				2,644,161		(a)
6	Localized Transmission Plant Held for Future Use				31,396,972		(a)
	Transmission Accumulated Depreciation						
7	Localized Transmission Accum. Depreciation				334,418	Sheet 9, Line 17(I)	(a)
8	General Plant Accum. Depreciation	26,085,325	Note 4			FF1 page 219 ln. 28, footnote	(a)
9	Less: Convex-related General Plant Acc Depr	3,717,252				Note 1	(a)
10	Subtotal: General Plant A/D, net of Convex (line 8-9)	22,368,074		0.0853% Note 2	19,080		(a)
11	Total (line 7+10)				353,497		(a)
12	Transmission Accumulated Deferred Taxes				323,209	Sheet 10, Line 32	(a)
13	Unam. Loss on Reacquired Debt (189)	12,599,425		0.0315% Note 3	3,969	FF1 page 111 ln. 81	(a)
14	Transmission Prepayments (165)	19,487,085	Note 4	0.0853% Note 2	16,622	FF1 page 110 ln. 57, footnote	(a)
15	Transmission Materials and Supplies	36,123,136		0.0853% Note 2	30,813	FF1 page 227 ln. 8	(a)
	Cash Working Capital						
16	Localized Operation & Maintenance Expense				32,286	Sheet 8, Line 29	(a)
17	Localized Administrative & General Expense				31,527	Sheet 8, Line 39	(b)
18	Subtotal (line 16+17)				63,813		(b)
19	12.5% allowance				0.125	x 45 / 360	(a)
20	Total current Year End (line 18*19)				7,977		(b)
21	Prior Year End Cash Working Capital				8,135	Note 1	(a)
22	Average Cash Working Capital [(line 20+21)/2]				8,056		(b)

Note 1: Reflects actual information per Eversource's accounting records.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247 Provided this support because these balances will be revised under the changed rates.

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Glenbrook Cables
Sheet 4a

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559	Note 2	46.27%	5.36%	Note 2	2.48%		
2	PREFERRED STOCK	$ 116,842,775		2.14%	4.80%		0.10%	0.10%	
3	COMMON EQUITY	$ 2,820,159,065		51.59%	11.07%	Note 1	5.71%	5.71%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399		100.00%			8.29%	5.81%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 8.29% Line 4, Col. (4)

(b) Federal Income Tax

$$= \left(\left(\text{R.O.E.} + \frac{\left(\text{Total Inv. (Tax Credit)} + \frac{\text{Eq. AFUDC of Deprec. Exp.}}{(1 - \text{Federal Income Tax Rate})} \right)}{\text{Total Inv. Base}} \right) \times \text{Federal Income Tax Rate} \right)$$

Source: Line 4, Col. (5); Sheet 8, Line 7; Sheet 6, Line 1; Sheet 1, Line 10; Federal Corporate Tax Rate

6
7

$$= \left(\left(5.81\% + \frac{\left((476) + \frac{1{,}968}{(1 - 35.00\%)} \right)}{33{,}423{,}887} \right) \times 35.00\% \right)$$

Federal Corporate Tax Rate

8 = 3.1309%

(c) State Income Tax

$$= \left(\left(\text{R.O.E.} + \frac{\left(\text{Total Inv. (Tax Credit)} + \frac{\text{Eq. AFUDC of Deprec. Exp.}}{(1 - \text{State Income Tax Rate})} \right)}{\text{Total Inv. Base}} + \text{Federal Income Tax} \right) \times \text{State Income Tax Rate} \right)$$

Source: Line 4, Col. (5); Sheet 8, Line 7; Sheet 6, Line 1; Sheet 1, Line 10; Line 8, Col. (1); Connecticut Corporate Tax Rate

9
10

$$= \left(\left(5.81\% + \frac{\left((476) + \frac{1{,}968}{(1 - 9.00\%)} \right)}{33{,}423{,}887} + 3.1309\% \right) \times 9.00\% \right)$$

Connecticut Corporate Tax Rate

11 = 0.8847%

12 (a)+(b)+(c) **Cost of Capital Rate** = 12.3056%

13	INVESTMENT BASE	33,423,887	Sheet 1, Line 10
14			
15	x Cost of Capital Rate	12.3056%	Line 12, Col. (1)
16	= Investment Return and Income Taxes	$ 4,113,010	

Total Investment Return and Income Taxes		
@11.07%	$ 4,113,010	Line 16, Col. (1)
@.67%	$ 11,317	Sheet 5a, Line 17
	$ 4,124,327	To Sheet 1a, Line 11

Note 1: ROE per FERC Order in Docket No. ER11-66 dated October 16, 2014.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes:

(1) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(2) Provided this support because the balance in "Total Inv. Base" will be revised under the Changed Rates

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Glenbrook Cables

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559	Note 2	46.27%					
2	PREFERRED STOCK	$ 116,842,775		2.14%					
3	COMMON EQUITY	$ 2,820,159,065		51.59%	0.50%	Note 1	0.26%	0.26%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399		100.00%			0.26%	0.26%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.26% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + (((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate)) / Total Inv. Base)) * Federal Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Federal Corporate Tax Rate

6 = ((0.26% + ((0 + 0) / 33,423,887)) * 35.00%)
7 (1 - 35.00%) Federal Corporate Tax Rate

8 = 0.1400%

(c) State Income Tax = ((R.O.E. + (((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate)) / Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Line 8, Col. (1); Connecticut Corporate Tax Rate

9 = ((0.26% + ((0 + 0) / 33,423,887) + 0.1400%) * 9.00%)
10 (1 - 9.00%) Connecticut Corporate Tax Rate

11 = 0.0396%

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.4396%

13 INVESTMENT BASE 33,423,887 Line 16, Col. (4)

14 x Cost of Capital Rate 0.4396% Line 12, Col. (1)

15 = Investment Return and Income Taxes $ 146,931 to Sheet 4a, Line 14(4)

Note 1: CAP on ROE incentives per FERC Order in Docket No. EL11-66 dated March 3, 2015.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.

Notes:
Notes:
(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-217, Schedule 2, Line 8

(2) The balance in "Total Inv. Base" is revised under the Changed Rates

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Glenbrook Cables
Sheet 8

Line No.	(A)	(B) Year End		(C) Localized Trans. Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Depreciation Expense							
1	Transmission Depreciation					59,851	Sheet 9, Line 19	(a)
2	General Depreciation	4,980,574	Note 4				FF1 page 336 ln. 10, footnote	(a)
3	*less:* Convex-related General Plant Depreciation Expense	1,110,693					Note 1	(a)
4	Subtotal: General Plant Depr Exp, net of Convex (line 2-3)	3,869,881		0.0853%	Note 2	3,301		(a)
5	Total (line 1+4)					63,152		(a)
6	Amortization of Loss on Reacquired Debt	1,309,927		0.0315%	Note 3	413	FF1 page 117 ln. 64	(a)
7	Amortization of Investment Tax Credits	1,511,975		0.0315%	Note 3	476	FF1 page 266 ln. 8 (f)	(a)
8	Property Taxes	120,836,131		0.0315%	Note 3	38,063	FF1 page 263 ln. 24i & 25i	(a)
	Payroll Tax Expense							
9	Federal Unemployment	5,226					FF1 page 262 ln. 3i, footnote	(a)
10	FICA	233,351					FF1 page 262 ln. 5i, footnote	(a)
11	Medicare	65,613					FF1 page 262 ln. 9i, footnote	(a)
12	CT Unemployment	16,786					FF1 page 262 ln. 15i, footnote	(a)
13	MA Unemployment	(285)					FF1 page 262 ln. 32i, footnote	(a)
14	MA Universal Health	64					FF1 page 262 ln. 33i, footnote	(a)
15	NH Unemployment	1,754					FF1 page 262.1 ln. 4i, footnote	(a)
16	NJ Unemployment	-					FF1 page 262 footnote	(a)
17	DC Unemployment	11					FF1 page 262.1 ln. 14i, footnote	(a)
18	FL Unemployment	1					FF1 page 262.1 ln. 18i, footnote	(a)
19	MI Unemployment	6					FF1 page 262.1 ln. 22i, footnote	(a)
20	NY Unemployment	-					FF1 page 262.1 ln. 10i, footnote	(a)
21	Total (Line 9 to 20)	322,527	Note 4	0.0853%	Note 2	275		(a)
	Transmission Operation and Maintenance							
22	Operation and Maintenance	77,432,007					FF1 page 321 ln. 112	(a)
23	Transmission of Electricity by Others - #565	21,727,966					FF1 page 321 ln. 96	(a)
24	Load Dispatching - #561	-					FF1 page 321 ln. 84	(a)
25	Account 561.1	3,245,594					FF1 page 321 ln. 85	(a)
26	Account 561.2	5,212,556					FF1 page 321 ln. 86	(a)
27	Account 561.3	2,238,612					FF1 page 321 ln. 87	(a)
28	Account 561.4	7,157,291					FF1 page 321 ln. 88	(a)
29	O&M (line 22 - lines 23 to 28)	37,849,988		0.0853%	Note 2	32,286		(a)
	Transmission-related Administrative and General							
30	Administrative and General	37,202,294	Note 4				FF1 page 320 ln. 197 b, footnote	(a)
31	less: Property Insurance (#924)	763,857	Note 4				FF1 Page 320 ln. 185 b, footnote	(a)
32	less: Regulatory Commission Expenses (#928)	2,749,411	Note 4				FF1 page 320 ln. 189 b, footnote	(a)
33	less: General Advertising Expense (#930.1)	10,766	Note 4				FF1 page 320 ln. 191 b, footnote	(a)
34	Subtotal (line 30 - lines 31 to 33)	33,678,260		0.0853%	Note 2	28,728		(a)
35	plus: Property Insurance	1,413,419		0.0315%	Note 3	445	FF1 page 323 ln. 185	(a)
36	plus: Trans. Regulatory Comm. Exp.	2,749,411		0.0853%	Note 2	2,345	FF1 page 320 ln. 189 b, footnote	(a)
37	plus: Trans. Related General Advertising Expense	10,766		0.0853%	Note 2	9	FF1 page 320 ln. 191 b, footnote	(a)
38	plus: Trans. Related Public Education Expense	-				-	FF1 page 114 ln. 49, footnote	(a)
39	Total A&G (sum of lines 34 to 38)	37,851,856				31,527		(b)
40	Transmission Related Taxes and Fees	9,854,673		0.0853%	Note 2	8,406	Note 5	(a)

Note 1: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.
Note 5: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment B.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247 Provided this support because these balances will be revised under the changed rates.

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 1a

Line	(A)	Attachment I Reference Section:	(B)	(C) Source	(D) Notes
	I. INVESTMENT BASE				
1	Transmission Plant	II(A)(1)(a)	3,169,795	Sheet 2, Line 5	(a)
2	Transmission Plant Held for Future Use	II(A)(1)(b)	-	Sheet 2, Line 6	(a)
3	Accumulated Depreciation	II(A)(1)(c)	116,694	Sheet 2, Line 11	(a)
4	Accumulated Deferred Income Taxes	II(A)(1)(d)	265,445	Sheet 2, Line 12	(a)
5	Loss On Reacquired Debt	II(A)(1)(e)	4,750	Sheet 2, Line 13	(a)
6	Net Investment (Line 1+2-3-4+5)		2,792,406		
7	Prepayments	II(A)(1)(f)	19,935	Sheet 2, Line 14	(a)
8	Materials & Supplies	II(A)(1)(g)	36,954	Sheet 2, Line 15	(a)
9	Cash Working Capital	II(A)(1)(h)	4,783	Sheet 2, Line 22	(b)
10	Total Investment Base (Line 6+7+8+9)		2,854,078		(b)
	II. REVENUE REQUIREMENTS				
11	Investment Return and Income Taxes	II(A)	368,465	Sheet 4a, Line 15(4)	(b)
12	Depreciation Expense	II(B)	78,802	Sheet 8, Line 5	(a)
13	Amortization of Loss on Reacquired Debt	II(C)	494	Sheet 8, Line 6	(a)
14	Investment Tax Credit	II(D)	(570)	Sheet 8, Line 7	(a)
15	Property Tax Expense	II(E)	45,555	Sheet 8, Line 8	(a)
16	Payroll Tax Expense	II(F)	330	Sheet 8, Line 21	(a)
17	Operation & Maintenance Expense	II(G)	38,721	Sheet 8, Line 29	(a)
18	Administrative & General Expense	II(H)	37,810	Sheet 8, Line 39	(b)
19	Support Expenses	II(I)	-		(a)
20	Transmission Related Taxes and Fees	II(J)	10,081	Sheet 8, Line 40	(a)
21	Total Revenue Requirements (Line 11 thru 20)		579,688		(b)

Note:
Investment Return and Income Taxes (line 11 above) was calculated based on the Total Investment Base at 11.07% ROE, plus the Localized PTF Transmission Base (lines 1-3-4) at the .67% capped Incremental ROE.

Notes:

(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247

(b) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247. Provided this support because these balances will be revised under the changed rates.

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
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Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 2

Line No.	(A)	(B) Trans. Related Average		(C) Allocation Factor		(D) Allocated to Localized	(E) Source		(F) Notes
	Transmission Plant								
1	Localized Transmission Plant					3,080,854	Sheet 3, Line 18	(a)	
2	Transmission General Plant	102,812,641	Note 4				FF1 page 204 ln. 96, footnote	(a)	
3	Less: Convex-related General Plant	15,870,872					Note 1	(a)	
4	Subtotal: General Plant, net of Convex (line 2 - 3)	86,941,769		0.1023%	Note 2	88,941		(a)	
5	Total (line 1+4)					3,169,795		(a)	
6	Localized Transmission Plant Held for Future Use					-		(a)	
	Transmission Accumulated Depreciation								
7	Localized Transmission Accum. Depreciation					93,811	Sheet 9, Line 10(I)	(a)	
8	General Plant Accum. Depreciation	26,085,325	Note 4				FF1 page 219 ln. 28, footnote	(a)	
9	Less: Convex-related General Plant Acc Depr	3,717,252					Note 1	(a)	
10	Subtotal: General Plant A/D, net of Convex (line 8-9)	22,368,074		0.1023%	Note 2	22,883		(a)	
11	Total (line 7+10)					116,694		(a)	
12	Transmission Accumulated Deferred Taxes					265,445	Sheet 10, Line 46	(a)	
13	Unam. Loss on Reacquired Debt (189)	12,599,425		0.0377%	Note 3	4,750	FF1 page 111 ln. 81	(a)	
14	Transmission Prepayments (165)	19,487,085	Note 4	0.1023%	Note 2	19,935	FF1 page 110 ln. 57, footnote	(a)	
15	Transmission Materials and Supplies	36,123,136		0.1023%	Note 2	36,954	FF1 page 227 ln. 8	(a)	
	Cash Working Capital								
16	Localized Operation & Maintenance Expense					38,721	Sheet 8, Line 29	(a)	
17	Localized Administrative & General Expense					37,810	Sheet 8, Line 39	(b)	
18	Subtotal (line 16+17)					76,531		(b)	
19	12.5% allowance					0.125	x 45 / 360	(a)	
20	Total current Year End (line 18*19)					9,566		(b)	
21	Prior Year End Cash Working Capital					-	Note 1	(a)	
22	Average Cash Working Capital [(line 20+21)/2]					4,783		(b)	

Note 1: Reflects actual information per Eversource's accounting records.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
Provided this support because these balances will be revised under the changed rates.

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 4a

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559	Note 2	46.27%	5.36%	Note 2	2.48%		
2	PREFERRED STOCK	$ 116,842,775		2.14%	4.80%		0.10%	0.10%	
3	COMMON EQUITY	$ 2,820,159,065		51.59%	11.07%	Note 1	5.71%	5.71%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399		100.00%			8.29%	5.81%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 8.29% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate)) / Total Inv. Base)) * Federal Income Tax Rate)

Line								
	Source:	Line 4, Col. (5)		Sheet 8, Line 7		Sheet 6, Line 1	Sheet 1, Line 10	Federal Corporate Tax Rate
6	= ((	5.81%	+ ((	(570)	+	2,360) /	2,854,078)) *	35.00%)
7			(	1	-	35.00%) Federal Corporate Tax Rate		
8	=	3.1622%						

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate)) / Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)

Line									
	Source:	Line 4, Col. (5)		Sheet 8, Line 7		Sheet 6, Line 1	Sheet 1, Line 10	Line 8, Col. (1)	Connecticut Corporate Tax Rate
9	= ((	5.81%	+ ((	(570)	+	2,360) /	2,854,078) +	3.1622%) *	9.00%)
10			(	1	-	9.00%) Connecticut Corporate Tax Rate			
11	=	0.8936%							

12 (a)+(b)+(c) **Cost of Capital Rate** = 12.3458%

Line			
13	INVESTMENT BASE	2,854,078	Sheet 1, Line 10
14			
15	x Cost of Capital Rate	12.3458%	Line 12, Col. (1)
16	= Investment Return and Income Taxes	$ 352,359	

Total Investment Return and Income Taxes			
@11.07%	$	352,359	Line 16, Col. (1)
@.67%	$	16,106	Sheet 5a, Line 17
	$	368,465	To Sheet 1a, Line 11

Note 1: ROE per FERC Order in Docket No. ER11-66 dated October 16, 2014.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes:

(1) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(2) Provided this support because the balance in "Total Inv. Base" will be revised under the Changed Rates

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 5a

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559	Note 2	46.27%					
2	PREFERRED STOCK	$ 116,842,775		2.14%					
3	COMMON EQUITY	$ 2,820,159,065		51.59%	0.50%	Note 1	0.26%	0.26%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399		100.00%			0.26%	0.26%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.26% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate) Total Inv. Base)) * Federal Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Federal Corporate Tax Rate

6 = ((0.26% + ((0 + 0) / 2,854,078)) * 35.00%)
7 (1 - 35.00%) Federal Corporate Tax Rate

8 = 0.1400%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate) Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Line 8, Col. (1); Connecticut Corporate Tax Rate

9 = ((0.26% + ((0 + 0) / 2,854,078) + 0.1400%) * 9.00%)
10 (1 - 9.00%) Connecticut Corporate Tax Rate

11 = 0.0396%

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.4396%

13 INVESTMENT BASE 2,854,078 Line 16, Col. (4)

14 x Cost of Capital Rate 0.4396% Line 12, Col. (1)

15 = Investment Return and Income Taxes $ 12,547 to Sheet 4a, Line 14(4)

Note 1: CAP on ROE incentives per FERC Order in Docket No. EL11-66 dated March 3, 2015.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.

Notes:
(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-217, Schedule 2, Line 8
(2) The balance in "Total Inv. Base" is revised under the Changed Rates

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 8

Line No.	(A)	(B) Year End		(C) Localized Trans. Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Depreciation Expense							
1	Transmission Depreciation					74,843	Sheet 9, Line 12	(a)
2	General Depreciation	4,980,574	Note 4				FF1 page 336 ln. 10, footnote	(a)
3	*less:* Convex-related General Plant Depreciation Expense	1,110,693					Note 1	(a)
4	Subtotal: General Plant Depr Exp, net of Convex (line 2-3)	3,869,881		0.1023%	Note 2	3,959		(a)
5	Total (line 1+4)					78,802		(a)
6	Amortization of Loss on Reacquired Debt	1,309,927		0.0377%	Note 3	494	FF1 page 117 ln. 64	(a)
7	Amortization of Investment Tax Credits	1,511,975		0.0377%	Note 3	570	FF1 page 266 ln. 8 (f)	(a)
8	Property Taxes	120,836,131		0.0377%	Note 3	45,555	FF1 page 263 ln. 24i & 25i	(a)
	Payroll Tax Expense							
9	Federal Unemployment	5,226					FF1 page 262 ln. 3i, footnote	(a)
10	FICA	233,351					FF1 page 262 ln. 5i, footnote	(a)
11	Medicare	65,613					FF1 page 262 ln. 9i, footnote	(a)
12	CT Unemployment	16,786					FF1 page 262 ln. 15i, footnote	(a)
13	MA Unemployment	(285)					FF1 page 262 ln. 32i, footnote	(a)
14	MA Universal Health	64					FF1 page 262 ln. 33i, footnote	(a)
15	NH Unemployment	1,754					FF1 page 262.1 ln. 4i, footnote	(a)
16	NJ Unemployment	-					FF1 page 262 footnote	(a)
17	DC Unemployment	11					FF1 page 262.1 ln. 14i, footnote	(a)
18	FL Unemployment	1					FF1 page 262.1 ln. 18i, footnote	(a)
19	MI Unemployment	6					FF1 page 262.1 ln. 22i, footnote	(a)
20	NY Unemployment	-					FF1 page 262.1 ln. 10i, footnote	(a)
21	Total (Line 9 to 20)	322,527	Note 4	0.1023%	Note 2	330		(a)
	Transmission Operation and Maintenance							
22	Operation and Maintenance	77,432,007					FF1 page 321 ln. 112	(a)
23	Transmission of Electricity by Others - #565	21,727,966					FF1 page 321 ln. 96	(a)
24	Load Dispatching - #561	-					FF1 page 321 ln. 84	(a)
25	Account 561.1	3,245,594					FF1 page 321 ln. 85	(a)
26	Account 561.2	5,212,556					FF1 page 321 ln. 86	(a)
27	Account 561.3	2,238,612					FF1 page 321 ln. 87	(a)
28	Account 561.4	7,157,291					FF1 page 321 ln. 88	(a)
29	O&M (line 22 - lines 23 to 28)	37,849,988		0.1023%	Note 2	38,721		(a)
	Transmission-related Administrative and General							
30	Administrative and General	37,202,294	Note 4				FF1 page 320 ln. 197 b, footnote	(a)
31	less: Property Insurance (#924)	763,857	Note 4				FF1 Page 320 ln. 185 b, footnote	(a)
32	less: Regulatory Commission Expenses (#928)	2,749,411	Note 4				FF1 page 320 ln. 189 b, footnote	(a)
33	less: General Advertising Expense (#930.1)	10,766	Note 4				FF1 page 320 ln. 191 b, footnote	(a)
34	Subtotal (line 30 - lines 31 to 33)	33,678,260		0.1023%	Note 2	34,453		(a)
35	plus: Property Insurance	1,413,419		0.0377%	Note 3	533	FF1 page 323 ln. 185	(a)
36	plus: Trans. Regulatory Comm. Exp.	2,749,411		0.1023%	Note 2	2,813	FF1 page 320 ln. 189 b, footnote	(a)
37	plus: Trans. Related General Advertising Expense	10,766		0.1023%	Note 2	11	FF1 page 320 ln. 191 b, footnote	(a)
38	plus: Trans. Related Public Education Expense	-				-	FF1 page 114 ln. 49, footnote	(a)
39	Total A&G (sum of lines 34 to 38)	37,851,856				37,810		(b)
40	Transmission Related Taxes and Fees	9,854,673		0.1023%	Note 2	10,081	Note 5	(a)

Note 1: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.
Note 5: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment B.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247 Provided this support because these balances will be revised under the changed rates.

Western Massachusetts Electric Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 1a

Line	(A) I. INVESTMENT BASE	Attachment I Reference Section:	(B)	(C) Source	(D) Notes
1	Transmission Plant	II(A)(1)(a)	7,316,798	Sheet 2, Line 5	(a)
2	Transmission Plant Held for Future Use	II(A)(1)(b)	-	Sheet 2, Line 6	(a)
3	Accumulated Depreciation	II(A)(1)(c)	290,421	Sheet 2, Line 11	(a)
4	Accumulated Deferred Income Taxes	II(A)(1)(d)	603,776	Sheet 2, Line 12	(a)
5	Loss On Reacquired Debt	II(A)(1)(e)	2,313	Sheet 2, Line 13	(a)
6	Net Investment (Line 1+2-3-4+5)		6,424,914		
7	Prepayments	II(A)(1)(f)	5,502	Sheet 2, Line 14	(a)
8	Materials & Supplies	II(A)(1)(g)	26,259	Sheet 2, Line 15	(a)
9	Cash Working Capital	II(A)(1)(h)	7,721	Sheet 2, Line 22	(b)
10	Total Investment Base (Line 6+7+8+9)		6,464,396		(b)
	II. REVENUE REQUIREMENTS				
11	Investment Return and Income Taxes	II(A)	779,406	Sheet 4a, Line 15(4)	(b)
12	Depreciation Expense	II(B)	184,929	Sheet 8, Line 5	(a)
13	Amortization of Loss on Reacquired Debt	II(C)	323	Sheet 8, Line 6	(a)
14	Investment Tax Credit	II(D)	(154)	Sheet 8, Line 7	(a)
15	Property Tax Expense	II(E)	144,952	Sheet 8, Line 8	(a)
16	Payroll Tax Expense	II(F)	157	Sheet 8, Line 21	(a)
17	Operation & Maintenance Expense	II(G)	54,519	Sheet 8, Line 29	(a)
18	Administrative & General Expense	II(H)	69,012	Sheet 8, Line 39	(b)
19	Support Expenses	II(I)	-		(a)
20	Transmission Related Taxes and Fees	II(J)	177	Sheet 8, Line 40	(a)
21	Total Revenue Requirements (Line 11 thru 20)		1,233,321		(b)

Note:
Investment Return and Income Taxes (line 11 above) was calculated based on the Total Investment Base at 11.07% ROE, plus the Localized PTF Transmission Base (lines 1-3-4) at the .67% capped Incremental ROE.

Notes:

(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247

(b) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247. Provided this support because these balances will be revised under the changed rates.

Western Massachusetts Electric Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 2

Line No.	(A)	(B) Trans. Related Average		(C) Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Transmission Plant							
1	Localized Transmission Plant					7,159,714	Sheet 3, Line 33	(a)
2	Transmission General Plant	18,348,753	Note 4	0.8561%	Note 2	157,084	FF1 page 204 ln. 96, footnote	(a)
3	Total (line 1+2)					7,316,798		(a)
4	Localized Transmission Plant Held for Future Use					-		(a)
	Transmission Accumulated Depreciation							
5	Localized Transmission Accum. Depreciation					256,419	Sheet 9, Line 27(I)	(a)
6	General Plant Accum.Depreciation	3,971,742	Note 4	0.8561%	Note 2	34,002	FF1 page 219 ln. 28, footnote	(a)
7	Total (line 5+6)					290,421		(a)
8								
9	Transmission Accumulated Deferred Taxes					603,776	Sheet 10, Line 46	(a)
10	Unam. Loss on Reacquired Debt (189)	533,928		0.4332%	Note 3	2,313	FF1 page 111 ln. 81	(a)
11	Transmission Prepayments (165)	642,737	Note 4	0.8561%	Note 2	5,502	FF1 page 110 ln. 57, footnote	(a)
12	Transmission Materials and Supplies	3,067,304		0.8561%	Note 2	26,259	FF1 page 227 ln. 8	(a)
	Cash Working Capital							
13	Localized Operation & Maintenance Expense					54,519	Sheet 8, Line 28	(a)
14	Localized Administrative & General Expense					69,012	Sheet 8, Line 38	(b)
15	Subtotal (line 13+14)					123,531		(b)
16	12.5% allowance					0.125	x 45 / 360	(a)
17	Total current Year End (line 15*16)					15,441		(b)
18	Prior Year End Cash Working Capital					-		(a)
19	Average Cash Working Capital [(line 17+18)/2]					7,721		(b)

Note 1: Reflects actual information per Eversource's accounting records.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247 Provided this support because these balances will be revised under the changed rates.

Western Massachusetts Electric Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 4a

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 568,072,183	Note 2	49.54%	4.31%	Note 2	2.14%		
2	PREFERRED STOCK	$ -		0.00%	0.00%		0.00%	0.00%	
3	COMMON EQUITY	$ 578,634,319		50.46%	11.07%	Note 1	5.59%	5.59%	
4	TOTAL INVESTMENT RETURN	$ 1,146,706,502		100.00%			7.73%	5.59%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 7.73% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / Total Inv. Base)) * Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

Source: Line 4, Col. (5); Sheet 8, Line 7; Sheet 6, Line 1; Sheet 1, Line 10; Federal Corporate Tax Rate

6 = ((5.59% + (((154) + 1,593) / 6,464,396)) * 35.00%)
7 (1 - 35.00%)
Federal Corporate Tax Rate

8 = 3.0220%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / Total Inv. Base) + Federal Income Tax) * State Income Tax Rate) / (1 - State Income Tax Rate)

Source: Line 4, Col. (5); Sheet 8, Line 7; Sheet 6, Line 1; Sheet 1, Line 10; Line 8, Col. (1); Massachusetts Corporate Tax Rate

9 = ((5.59% + (((154) + 1,593) / 6,464,396) + 3.0220%) * 8.00%)
10 (1 - 8.00%)
Massachusetts Corporate Tax Rate

11 = 0.7508%

12 (a)+(b)+(c) **Cost of Capital Rate** = 11.5028%

13 INVESTMENT BASE 6,464,396 Sheet 1, Line 10
14
15 x Cost of Capital Rate 11.5028% Line 12, Col. (1)
16 = Investment Return and Income Taxes $ 743,587

Total Investment Return and Income Taxes			
@11.07%	$	743,587	Line 16, Col. (1)
@.67%	$	35,819	Sheet 5, Line 17
	$	779,406	To Sheet 1a, Line 11

Note 1: ROE per FERC Order in Docket No. ER04-157 dated March 24, 2008.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes:

(1) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(2) Provided this support because the balance in "Total Inv. Base" will be revised under the Changed Rates

Western Massachusetts Electric Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 568,072,183	Note 2	49.54%					
2	PREFERRED STOCK	$ -		0.00%					
3	COMMON EQUITY	$ 578,634,319		50.46%	0.50%	Note 1	0.25%	0.25%	
4	TOTAL INVESTMENT RETURN	$ 1,146,706,502		100.00%			0.25%	0.25%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.25% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate)) / Total Inv. Base)) * Federal Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Federal Corporate Tax Rate

6 = ((0.25% + ((0 + 0) / 6,464,396)) * 35.00%)
7 (1 - 35.00%)
Federal Corporate Tax Rate

8 = 0.1346%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate)) / Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Line 8, Col. (1); Massachusetts Corporate Tax Rate

9 = ((0.25% + ((0 + 0) / 6,464,396) + 0.1346%) * 8.00%)
10 (1 - 8.00%)
Massachusetts Corporate Tax Rate

11 = 0.0334%

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.4180%

13 INVESTMENT BASE 6,464,396 Line 16, Col. (4)

14 x Cost of Capital Rate 0.4180% Line 12, Col. (1)

15 = Investment Return and Income Taxes $ 27,021 to Sheet 4a, Line 14(4)

Note 1: CAP on ROE incentives per FERC Order in Docket No. EL11-66 dated March 3, 2015.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.

Notes:

(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-217, Schedule 2, Line 8
(2) The balance in "Total Inv. Base" is revised under the Changed Rates

Western Massachusetts Electric Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Present Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 8

Line No.	(A)	(B) Year End		(C) Localized Trans. Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Depreciation Expense							
1	Transmission Depreciation					178,169	Sheet 9, Line 29	(a)
2	General Depreciation	789,658	Note 4	0.8561%	Note 2	6,760	FF1 page 336 ln. 10, footnote	(a)
3	Total (line 1+4)					184,929		(a)
4								
5	Amortization of Loss on Reacquired Debt	74,501		0.4332%	Note 3	323	FF1 pg 117 ln. 64	(a)
6	Amortization of Investment Tax Credits	35,604		0.4332%	Note 3	154	FF1 page 266 ln. 8(f), footnote	(a)
7	Property Taxes	33,460,690		0.4332%	Note 3	144,952	FF1 page 263 ln. 31i & 32i	(a)
	Payroll Tax Expense							
8	Federal Unemployment	283					FF1 page 262 ln. 3i, footnote	(a)
9	FICA	13,202					FF1 page 262 ln. 5i, footnote	(a)
10	Medicare	3,757					FF1 page 262 ln. 9i, footnote	(a)
11	CT Unemployment	852					FF1 page 262 ln. 13i, footnote	(a)
12	MA Unemployment	69					FF1 page 262 ln. 22i, footnote	(a)
13	MA Universal Health	19					FF1 page 262 ln. 27i, footnote	(a)
14	NH Unemployment	108					FF1 page 262 ln. 37i, footnote	(a)
15	NJ Unemployment	-					FF1 page 262, footnote	(a)
16	DC Unemployment	1					FF1 page 262.1 ln. 6i, footnote	(a)
17	FL Unemployment	-					FF1 page 262, footnote	(a)
18	MI Unemployment	-					FF1 page 262, footnote	(a)
19	NY Unemployment	-					FF1 page 262, footnote	(a)
20	Total (Line 9 to 20)	18,291	Note 4	0.8561%	Note 2	157		
	Transmission Operation and Maintenance							
21	Operation and Maintenance	20,725,279					FF1 page 321 ln. 112	(a)
22	Transmission of Electricity by Others - #565	13,174,678					FF1 page 321 ln. 96	(a)
23	Load Dispatching - #561	-					FF1 page 321 ln. 84	(a)
24	Account 561.1	12,368					FF1 page 321 ln. 85	(a)
25	Account 561.2	50,569					FF1 page 321 ln. 86	(a)
26	Account 561.3	13,262					FF1 page 321 ln. 87	(a)
27	Account 561.4	1,106,108					FF1 page 321 ln. 88	(a)
28	O&M (line 22 - lines 23 to 28)	6,368,294		0.8561%	Note 2	54,519		(a)
	Transmission-related Administrative and General							
29	Administrative and General	8,041,502	Note 4				FF1 page 320 ln. 197, footnote	(a)
30	less: Property Insurance (#924)	106,141	Note 4				FF1 Page 320 ln. 185 b, footnote	(a)
31	less: Regulatory Commission Expenses (#928)	563,123	Note 4				FF1 page 320 ln. 189 b, footnote	(a)
32	less: General Advertising Expense (#930.1)	2,857	Note 4				FF1 page 320 ln. 191 b, footnote	(a)
33	Subtotal (line 30 - lines 31 to 33)	7,369,381		0.8561%	Note 2	63,089		(a)
34	plus: Property Insurance	248,747		0.4332%	Note 3	1,078	FF1 page 323 ln. 185	(a)
35	plus: Trans. Regulatory Comm. Exp.	563,123		0.8561%	Note 2	4,821	FF1 page 320 ln. 189 b, footnote	(a)
36	plus: Trans. Related General Advertising Expense	2,857		0.8561%	Note 2	24	FF1 page 320 ln. 191 b, footnote	(a)
37	plus: Trans. Related Public Education Expense	-				-	FF1 page 114 ln. 49, footnote	(a)
38	Total A&G (sum of lines 34 to 38)	8,184,108				69,012		(b)
39	Transmission Related Taxes and Fees	20,627		0.8561%	Note 2	177	Note 5	(a)

Note 1: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.
Note 5: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment B.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247 Provided this support because these balances will be revised under the changed rates.

Exhibit No. ES-226
Schedule 3

Category B Revenue Requirements under the Changed Rates For 2016

Eversource Energy Service Company

CL&P and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I) of the ISO-NE OATT
For the Calendar year 2016

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)=(C)+(D)+(E)+(F)+(G)
			CL&P				WMECO	
Line	Description	Reference	B-N	M-N	G-C	GSRP	GSRP	Total
1	2014 Actual Schedule 21-ES, Category B Rev. Req.		$ 19,557,746 (1)	$ 10,331,155 (2)	$ 4,304,873 (3)	$ 587,960 (4)	$ 1,251,990 (5)	$ 36,033,724
2	Estimated 2015 Plant Additions	(6)	$ -	$ -	$ -	$ -	$ -	$ -
3	Carrying Charge Factor (CCF)	(6)	0.00%	0.00%	0.00%	0.00%	0.00%	
4	2015 Incremental Estimated Schedule 21-ES, Cat. B Rev. Req.	Line 2 x 3	-	-	-	-	-	$ -
5	Total Estimated Schedule 21-ES, Cat. B Revenue Requirement for 2015	Line 1 + 4	$ 19,557,746	$ 10,331,155	$ 4,304,873	$ 587,960	$ 1,251,990	$ 36,033,724
6	Estimated 2016 Plant Additions	(6)	$ -	$ -	$ -	$ -	$ -	$ -
7	Carrying Charge Factor (CCF)	(6)	0.00%	0.00%	0.00%	0.00%	0.00%	
8	2016 Incremental Estimated Schedule 21-ES, Cat. B Rev. Req.	Line 7 x 8	-	-	-	-	-	$ -
9	Total Estimated Schedule 21-ES, Cat. B Revenue Requirement for 2016	Line 6 + 9	$ 19,557,746	$ 10,331,155	$ 4,304,873	$ 587,960	$ 1,251,990	$ 36,033,724

Notes:
(1) Exhibit No. ES-226, Schedule 3, Page 2 of 26, Line 22(B)
(2) Exhibit No. ES-226, Schedule 3, Page 7 of 26, Line 22(B)
(3) Exhibit No. ES-226, Schedule 3, Page 12 of 26, Line 22(B)
(4) Exhibit No. ES-226, Schedule 3, Page 17 of 26, Line 22(B)
(5) Exhibit No. ES-226, Schedule 3, Page 22 of 26, Line 22(B)
(6) These are no forecasted plant additions for Category B

The Connecticut Light and Power Company
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Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Bethel-Norwalk
Sheet 1a

Line No.	(A)	Attachment I Reference Section:	(B)	(C) Source	(D) Notes
	I. INVESTMENT BASE				
1	Transmission Plant	II(A)(1)(a)	125,258,704	Sheet 2, Line 5	(a)
2	Transmission Plant Held for Future Use	II(A)(1)(b)	-	Sheet 2, Line 6	(a)
3	Accumulated Depreciation	II(A)(1)(c)	23,816,817	Sheet 2, Line 11	(a)
4	Accumulated Deferred Income Taxes	II(A)(1)(d)	19,494,337	Sheet 2, Line 12	(a)
5	Loss On Reacquired Debt	II(A)(1)(e)	187,920	Sheet 2, Line 13	(a)
6	Other Regulatory Assets	II(A)(1)(f)	289,044	Sheet 2, Line 14	(b)
7	Net Investment (Line 1+2-3-4+5)		82,424,514		(b)
8	Prepayments	II(A)(1)(g)	787,415	Sheet 2, Line 15	(a)
9	Materials & Supplies	II(A)(1)(h)	1,459,628	Sheet 2, Line 16	(a)
10	Cash Working Capital	II(A)(1)(i)	399,453	Sheet 2, Line 23	(b)
11	Total Investment Base (Line 6+7+8+9)		85,071,010		(b)
	II. REVENUE REQUIREMENTS				
12	Investment Return and Income Taxes	II(A)	10,984,216	Sheet 4a, Line 15(4)	(b)
13	Depreciation Expense	II(B)	3,051,146	Sheet 8, Line 5	(a)
14	Amortization of Loss on Reacquired Debt	II(C)	19,538	Sheet 8, Line 6	(a)
15	Investment Tax Credit	II(D)	(22,551)	Sheet 8, Line 7	(a)
16	Property Tax Expense	II(E)	1,802,271	Sheet 8, Line 8	(a)
17	Payroll Tax Expense	II(F)	13,032	Sheet 8, Line 21	(a)
18	Operation & Maintenance Expense	II(G)	1,529,404	Sheet 8, Line 29	(a)
19	Administrative & General Expense	II(H)	1,782,492	Sheet 8, Line 40	(b)
20	Support Expenses	II(I)	-		(a)
21	Transmission Related Taxes and Fees	II(J)	398,198	Sheet 8, Line 41	(a)
22	Total Revenue Requirements (Line 11 thru 20)		19,557,746		(b)

Note:
Investment Return and Income Taxes (line 11 above) was calculated based on the Total Investment Base at 11.07% ROE, plus the Localized Post-2003 PTF Transmission Base (lines 1-3-4) at the .67% capped Incremental ROE.

Notes:

(a) **Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247**

(b) **Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset**

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
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Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Bethel-Norwalk
Sheet 2

Line No.	(A)	(B) Trans. Related Average		(C) Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Transmission Plant							
1	Localized Transmission Plant					121,745,648	Sheet 3, Line 19	(a)
2	Transmission General Plant	102,812,641	Note 4				FF1 page 204 ln. 96, footnote	(a)
3	Less: Convex-related General Plant	15,870,872					Note 1	(a)
4	Subtotal: General Plant, net of Convex (line 2 - 3)	86,941,769		4.0407%	Note 2	3,513,056		(a)
5	Total (line 1+4)					125,258,704		(a)
6	Localized Transmission Plant Held for Future Use					-		(a)
	Transmission Accumulated Depreciation							
7	Localized Transmission Accum. Depreciation					22,912,990	Sheet 9, Line 56(I)	(a)
8	General Plant Accum. Depreciation	26,085,325	Note 4				FF1 page 219 ln. 28, footnote	(a)
9	Less: Convex-related General Plant Acc Depr	3,717,252					Note 1	(a)
10	Subtotal: General Plant A/D, net of Convex (line 8-9)	22,368,074		4.0407%	Note 2	903,827		(a)
11	Total (line 7+10)					23,816,817		(a)
12	Transmission Accumulated Deferred Taxes					19,494,337	Sheet 10, Line 111	(a)
13	Unam. Loss on Reacquired Debt (189)	12,599,425		1.4915%	Note 3	187,920	FF1 page 111 ln. 81	(a)
14	Localized Transmission Other Regulatory Assets	7,153,326		4.0407%		289,044	Exhibit No. ES-220, Page 1 of 8, Line 4(B)	(b)
15	Transmission Prepayments (165)	19,487,085	Note 4	4.0407%	Note 2	787,415	FF1 page 110 ln. 57, footnote	(a)
16	Transmission Materials and Supplies	36,123,136		4.0407%	Note 2	1,459,628	FF1 page 227 ln. 8	(a)
	Cash Working Capital							
17	Localized Operation & Maintenance Expense					1,529,404	Sheet 8, Line 29	(a)
18	Localized Administrative & General Expense					1,782,492	Sheet 8, Line 40	(c)
19	Subtotal (line 16+17)					3,311,896		(c)
20	12.5% allowance					0.125	x 45 / 360	(a)
21	Total current Year End (line 18*19)					413,987		(c)
22	Prior Year End Cash Working Capital					384,919	Note 1	(a)
23	Average Cash Working Capital [(line 20+21)/2]					399,453		(c)

Note 1: Reflects actual information per Eversource's accounting records.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset
(c) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Bethel-Norwalk
Sheet 4a

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559	Note 2	46.27%	5.36%	Note 2	2.48%		
2	PREFERRED STOCK	$ 116,842,775		2.14%	4.80%		0.10%	0.10%	
3	COMMON EQUITY	$ 2,820,159,065		51.59%	11.07%	Note 1	5.71%	5.71%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399		100.00%			8.29%	5.81%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 8.29% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + (((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate)) / Total Inv. Base)) * Federal Income Tax Rate)

Line		Source: Line 4, Col. (5)	Sheet 8, Line 7		Sheet 6, Line 1		Sheet 1, Line 10		Federal Corporate Tax Rate	
6	= ((	5.81%	+ (((22,551)	+	93,235	) /	85,071,010	)) *	35.00%	)
7			(1	-	35.00% (Federal Corporate Tax Rate)	)				
8	=	3.1732%								

(c) State Income Tax = ((R.O.E. + (((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate)) / Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)

Line		Source: Line 4, Col. (5)	Sheet 8, Line 7		Sheet 6, Line 1		Sheet 1, Line 10		Line 8, Col. (1)		Connecticut Corporate Tax Rate	
9	= ((	5.81%	+ (((22,551)	+	93,235	) /	85,071,010	) +	3.1732%	) *	9.00%	)
10			(1	-	9.00% (Connecticut Corporate Tax Rate)	)						
11	=	0.8967%										

12 (a)+(b)+(c) **Cost of Capital Rate** = 12.3599%

Line			
13	INVESTMENT BASE	85,071,010	Sheet 1, Line 10
14			
15	x Cost of Capital Rate	12.3599%	Line 12, Col. (1)
16	= Investment Return and Income Taxes	$ 10,514,692	

Total Investment Return and Income Taxes		
@11.07%	$ 10,514,692	Line 16, Col. (1)
@.67%	$ 469,524	Sheet 5a, Line 17
	$ 10,984,216	To Sheet 1a, Line 11

Note 1: ROE per FERC Order in Docket No. ER11-66 dated October 16, 2014.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes:

(1) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
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Bethel-Norwalk

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559	Note 2	46.27%					
2	PREFERRED STOCK	$ 116,842,775		2.14%					
3	COMMON EQUITY	$ 2,820,159,065		51.59%	0.50%	Note 1	0.26%	0.26%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399		100.00%			0.26%	0.26%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.26% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate)) / Total Inv. Base)) * Federal Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Federal Corporate Tax Rate

6 = ((0.26% + ((0 + 0) / Line 16, Col. (4) 85,071,010)) * 35.00%)
7 (1 - 35.00% Federal Corporate Tax Rate)

8 = 0.1400%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate)) / Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Line 8, Col. (1); Connecticut Corporate Tax Rate

9 = ((0.26% + ((0 + 0) / 85,071,010) + 0.1400%) * 9.00%)
10 (1 - 9.00% Connecticut Corporate Tax Rate)

11 = 0.0396%

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.4396%

13 INVESTMENT BASE 85,071,010 Line 16, Col. (4)

14 x Cost of Capital Rate 0.4396% Line 12, Col. (1)

15 = Investment Return and Income Taxes $ 373,972 to Sheet 4a, Line 14(4)

Note 1: CAP on ROE incentives per FERC Order in Docket No. EL11-66 dated March 3, 2015.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.

Notes:

(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-224, Schedule 1, Page 2 of 4, Line 18
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Bethel-Norwalk
Sheet 8

Line No.	(A)	(B) Year End		(C) Localized Trans. Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Depreciation Expense							
1	Transmission Depreciation					2,894,776	Sheet 9, Line 58	(a)
2	General Depreciation	4,980,574	Note 4				FF1 page 336 ln. 10, footnote	(a)
3	*less:* Convex-related General Plant Depreciation Expense	1,110,693					Note 1	(a)
4	Subtotal: General Plant Depr Exp, net of Convex (line 2-3)	3,869,881		4.0407%	Note 2	156,370		(a)
5	Total (line 1+4)					3,051,146		(a)
6	Amortization of Loss on Reacquired Debt	1,309,927		1.4915%	Note 3	19,538	FF1 page 117 ln. 64	(a)
7	Amortization of Investment Tax Credits	1,511,975		1.4915%	Note 3	22,551	FF1 page 266 ln. 8 (f)	(a)
8	Property Taxes	120,836,131		1.4915%	Note 3	1,802,271	FF1 page 263 ln. 24i & 25i	(a)
	Payroll Tax Expense							
9	Federal Unemployment	5,226					FF1 page 262 ln. 3i, footnote	(a)
10	FICA	233,351					FF1 page 262 ln. 5i, footnote	(a)
11	Medicare	65,613					FF1 page 262 ln. 9i, footnote	(a)
12	CT Unemployment	16,786					FF1 page 262 ln. 15i, footnote	(a)
13	MA Unemployment	(285)					FF1 page 262 ln. 32i, footnote	(a)
14	MA Universal Health	64					FF1 page 262 ln. 33i, footnote	(a)
15	NH Unemployment	1,754					FF1 page 262.1 ln. 4i, footnote	(a)
16	NJ Unemployment	-					FF1 page 262 footnote	(a)
17	DC Unemployment	11					FF1 page 262.1 ln. 14i, footnote	(a)
18	FL Unemployment	1					FF1 page 262.1 ln. 18i, footnote	(a)
19	MI Unemployment	6					FF1 page 262.1 ln. 22i, footnote	(a)
20	NY Unemployment	-					FF1 page 262.1 ln. 10i, footnote	(a)
21	Total (Line 9 to 20)	322,527	Note 4	4.0407%	Note 2	13,032		
	Transmission Operation and Maintenance							
22	Operation and Maintenance	77,432,007					FF1 page 321 ln. 112	(a)
23	Transmission of Electricity by Others - #565	21,727,966					FF1 page 321 ln. 96	(a)
24	Load Dispatching - #561	-					FF1 page 321 ln. 84	(a)
25	Account 561.1	3,245,594					FF1 page 321 ln. 85	(a)
26	Account 561.2	5,212,556					FF1 page 321 ln. 86	(a)
27	Account 561.3	2,238,612					FF1 page 321 ln. 87	(a)
28	Account 561.4	7,157,291					FF1 page 321 ln. 88	(a)
29	O&M (line 22 - lines 23 to 28)	37,849,988		4.0407%	Note 2	1,529,404		(a)
	Transmission-related Administrative and General							
30	Administrative and General	37,202,294	Note 4				FF1 page 320 ln. 197 b, footnote	(a)
31	less: Property Insurance (#924)	763,857	Note 4				FF1 Page 320 ln. 185 b, footnote	(a)
32	less: Regulatory Commission Expenses (#928)	2,749,411	Note 4				FF1 page 320 ln. 189 b, footnote	(a)
33	less: General Advertising Expense (#930.1)	10,766	Note 4				FF1 page 320 ln. 191 b, footnote	(a)
34	Subtotal (line 30 - lines 31 to 33)	33,678,260		4.0407%	Note 2	1,360,837		(a)
35	plus: Property Insurance	1,413,419		1.4915%	Note 3	21,081	FF1 page 323 ln. 185	(a)
36	plus: Trans. Regulatory Comm. Exp.	2,749,411		4.0407%	Note 2	111,095	FF1 page 320 ln. 189 b, footnote	(a)
37	plus: Trans. Related General Advertising Expense	10,766		4.0407%	Note 2	435	FF1 page 320 ln. 191 b, footnote	(a)
38	plus: Trans. Related Public Education Expense	-				-	FF1 page 114 ln. 49, footnote	(a)
39	plus: Trans. Merger-Related Costs	7,153,326		4.0407%		289,044	Exhibit No. ES-220, Page 1 of 8, Line 2(B)	(b)
40	Total A&G (sum of lines 34 to 38)	45,005,182				1,782,492		(b)
41	Transmission Related Taxes and Fees	9,854,673		4.0407%	Note 2	398,198	Note 5	(a)

Note 1: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.
Note 5: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment B.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Middletown-Norwalk
Sheet 1a

Line No.	(A)	Attachment I Reference Section:	(B)	(C) Source	(D) Notes
	I. INVESTMENT BASE				
1	Transmission Plant	II(A)(1)(a)	62,028,638	Sheet 2, Line 5	(a)
2	Transmission Plant Held for Future Use	II(A)(1)(b)	-	Sheet 2, Line 6	(a)
3	Accumulated Depreciation	II(A)(1)(c)	9,382,562	Sheet 2, Line 11	(a)
4	Accumulated Deferred Income Taxes	II(A)(1)(d)	7,626,580	Sheet 2, Line 12	(a)
5	Loss On Reacquired Debt	II(A)(1)(e)	93,059	Sheet 2, Line 13	(a)
6	Other Regulatory Assets	II(A)(1)(f)	143,138	Sheet 2, Line 14	(b)
7	Net Investment (Line 1+2-3-4+5)		45,255,693		(b)
8	Prepayments	II(A)(1)(g)	389,937	Sheet 2, Line 15	(a)
9	Materials & Supplies	II(A)(1)(h)	722,824	Sheet 2, Line 16	(a)
10	Cash Working Capital	II(A)(1)(i)	197,902	Sheet 2, Line 23	(b)
11	Total Investment Base (Line 6+7+8+9)		46,566,356		(b)
	II. REVENUE REQUIREMENTS				
12	Investment Return and Income Taxes	II(A)	6,011,773	Sheet 4a, Line 15(4)	(b)
13	Depreciation Expense	II(B)	1,584,643	Sheet 8, Line 5	(a)
14	Amortization of Loss on Reacquired Debt	II(C)	9,675	Sheet 8, Line 6	(a)
15	Investment Tax Credit	II(D)	(11,167)	Sheet 8, Line 7	(a)
16	Property Tax Expense	II(E)	892,496	Sheet 8, Line 8	(a)
17	Payroll Tax Expense	II(F)	6,454	Sheet 8, Line 21	(a)
18	Operation & Maintenance Expense	II(G)	757,378	Sheet 8, Line 29	(a)
19	Administrative & General Expense	II(H)	882,711	Sheet 8, Line 40	(b)
20	Support Expenses	II(I)	-		(a)
21	Transmission Related Taxes and Fees	II(J)	197,192	Sheet 8, Line 41	(a)
22	Total Revenue Requirements (Line 11 thru 20)		10,331,155		(b)

Note:
Investment Return and Income Taxes (line 11 above) was calculated based on the Total Investment Base at 11.07% ROE, plus the Localized Post-2003 PTF Transmission Base (lines 1-3-4) at the .67% capped Incremental ROE.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Middletown-Norwalk
Sheet 2

Line No.	(A)	(B) Trans. Related Average		(C) Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Transmission Plant							
1	Localized Transmission Plant					60,288,933	Sheet 3, Line 18	(a)
2	Transmission General Plant	102,812,641	Note 4				FF1 page 204 ln. 96, footnote	(a)
3	Less: Convex-related General Plant	15,870,872					Note 1	(a)
4	Subtotal: General Plant, net of Convex (line 2 - 3)	86,941,769		2.0010%	Note 2	1,739,705		(a)
5	Total (line 1+4)					62,028,638		(a)
6	Localized Transmission Plant Held for Future Use					-		(a)
	Transmission Accumulated Depreciation							
7	Localized Transmission Accum. Depreciation					8,934,977	Sheet 9, Line 84(I)	(a)
8	General Plant Accum. Depreciation	26,085,325	Note 4				FF1 page 219 ln. 28, footnote	(a)
9	Less: Convex-related General Plant Acc Depr	3,717,252					Note 1	(a)
10	Subtotal: General Plant A/D, net of Convex (line 8-9)	22,368,074		2.0010%	Note 2	447,585		(a)
11	Total (line 7+10)					9,382,562		(a)
12	Transmission Accumulated Deferred Taxes					7,626,580	Sheet 10, Line 105	(a)
13	Unam. Loss on Reacquired Debt (189)	12,599,425		0.7386%	Note 3	93,059	FF1 page 111 ln. 81	(a)
14	Localized Transmission Other Regulatory Assets	7,153,326		2.0010%		143,138	Exhibit No. ES-220, Page 1 of 8, Line 4(B)	(b)
15	Transmission Prepayments (165)	19,487,085	Note 4	2.0010%	Note 2	389,937	FF1 page 110 ln. 57, footnote	(a)
16	Transmission Materials and Supplies	36,123,136		2.0010%	Note 2	722,824	FF1 page 227 ln. 8	(a)
	Cash Working Capital							
17	Localized Operation & Maintenance Expense					757,378	Sheet 8, Line 29	(a)
18	Localized Administrative & General Expense					882,711	Sheet 8, Line 40	(c)
19	Subtotal (line 16+17)					1,640,089		(c)
20	12.5% allowance					0.125	x 45 / 360	(a)
21	Total current Year End (line 18*19)					205,011		(c)
22	Prior Year End Cash Working Capital					190,793	Note 1	(a)
23	Average Cash Working Capital [(line 20+21)/2]					197,902		(c)

Note 1: Reflects actual information per Eversource's accounting records.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset
(c) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Middletown-Norwalk
Sheet 4a

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559	Note 2	46.27%	5.36%	Note 2	2.48%		
2	PREFERRED STOCK	$ 116,842,775		2.14%	4.80%		0.10%	0.10%	
3	COMMON EQUITY	$ 2,820,159,065		51.59%	11.07%	Note 1	5.71%	5.71%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399		100.00%			8.29%	5.81%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 8.29% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / Total Inv. Base)) * Federal Income Tax Rate)
(1 - Federal Income Tax Rate)

Source: Line 4, Col. (5); Sheet 8, Line 7; Sheet 6, Line 1; Sheet 1, Line 10; Federal Corporate Tax Rate

6 = ((5.81% + (((11,167) + 46,171) / 46,566,356)) * 35.00%)
7 (1 - 35.00%)
Federal Corporate Tax Rate

8 = 3.1689%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)
(1 - State Income Tax Rate)

Source: Line 4, Col. (5); Sheet 8, Line 7; Sheet 6, Line 1; Sheet 1, Line 10; Line 8, Col. (1); Connecticut Corporate Tax Rate

9 = ((5.81% + (((11,167) + 46,171) / 46,566,356) + 3.1689%) * 9.00%)
10 (1 - 9.00%)
Connecticut Corporate Tax Rate

11 = 0.8955%

12 (a)+(b)+(c) **Cost of Capital Rate** = 12.3544%

Line			
13	INVESTMENT BASE	46,566,356	Sheet 1, Line 10
14			
15	x Cost of Capital Rate	12.3544%	Line 12, Col. (1)
16	= Investment Return and Income Taxes	$ 5,752,994	

Total Investment Return and Income Taxes

@11.07%	$ 5,752,994	Line 16, Col. (1)
@.67%	$ 258,779	Sheet 5a, Line 17
	$ 6,011,773	To Sheet 1a, Line 11

Note 1: ROE per FERC Order in Docket No. ER11-66 dated October 16, 2014.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes:

(1) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Middletown-Norwalk
Sheet 5a

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559	Note 2	46.27%					
2	PREFERRED STOCK	$ 116,842,775		2.14%					
3	COMMON EQUITY	$ 2,820,159,065		51.59%	0.50%	Note 1	0.26%	0.26%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399		100.00%			0.26%	0.26%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.26% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate)) / Total Inv. Base)) * Federal Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Federal Corporate Tax Rate

6 = ((0.26% + ((0 + 0) / Line 16, Col. (4) 46,566,356)) * 35.00%)
7 (1 - 35.00%) Federal Corporate Tax Rate

8 = 0.1400%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate)) / Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Line 8, Col. (1); Connecticut Corporate Tax Rate

9 = ((0.26% + ((0 + 0) / 46,566,356) + 0.1400%) * 9.00%)
10 (1 - 9.00%) Connecticut Corporate Tax Rate

11 = 0.0396%

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.4396%

13	INVESTMENT BASE	46,566,356	Line 16, Col. (4)
14	x Cost of Capital Rate	0.4396%	Line 12, Col. (1)
15	= Investment Return and Income Taxes	$ 204,706	to Sheet 4a, Line 14(4)

Note 1: CAP on ROE incentives per FERC Order in Docket No. EL11-66 dated March 3, 2015.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.

Notes:

(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-224, Schedule 1, Page 2 of 4, Line 18
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Middletown-Norwalk
Sheet 8

Line No.	(A)	(B) Year End		(C) Localized Trans. Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Depreciation Expense							
1	Transmission Depreciation					1,507,207	Sheet 9, Line 86	(a)
2	General Depreciation	4,980,574	Note 4				FF1 page 336 ln. 10, footnote	(a)
3	*less:* Convex-related General Plant Depreciation Expense	1,110,693					Note 1	(a)
4	Subtotal: General Plant Depr Exp, net of Convex (line 2-3)	3,869,881		2.0010%	Note 2	77,436		(a)
5	Total (line 1+4)					1,584,643		(a)
6	Amortization of Loss on Reacquired Debt	1,309,927		0.7386%	Note 3	9,675	FF1 page 117 ln. 64	(a)
7	Amortization of Investment Tax Credits	1,511,975		0.7386%	Note 3	11,167	FF1 page 266 ln. 8 (f)	(a)
8	Property Taxes	120,836,131		0.7386%	Note 3	892,496	FF1 page 263 ln. 24i & 25i	(a)
	Payroll Tax Expense							
9	Federal Unemployment	5,226					FF1 page 262 ln. 3i, footnote	(a)
10	FICA	233,351					FF1 page 262 ln. 5i, footnote	(a)
11	Medicare	65,613					FF1 page 262 ln. 9i, footnote	(a)
12	CT Unemployment	16,786					FF1 page 262 ln. 15i, footnote	(a)
13	MA Unemployment	(285)					FF1 page 262 ln. 32i, footnote	(a)
14	MA Universal Health	64					FF1 page 262 ln. 33i, footnote	(a)
15	NH Unemployment	1,754					FF1 page 262.1 ln. 4i, footnote	(a)
16	NJ Unemployment	-					FF1 page 262 footnote	(a)
17	DC Unemployment	11					FF1 page 262.1 ln. 14i, footnote	(a)
18	FL Unemployment	1					FF1 page 262.1 ln. 18i, footnote	(a)
19	MI Unemployment	6					FF1 page 262.1 ln. 22i, footnote	(a)
20	NY Unemployment	-					FF1 page 262.1 ln. 10i, footnote	(a)
21	Total (Line 9 to 20)	322,527	Note 4	2.0010%	Note 2	6,454		
	Transmission Operation and Maintenance							
22	Operation and Maintenance	77,432,007					FF1 page 321 ln. 112	(a)
23	Transmission of Electricity by Others - #565	21,727,966					FF1 page 321 ln. 96	(a)
24	Load Dispatching - #561	-					FF1 page 321 ln. 84	(a)
25	Account 561.1	3,245,594					FF1 page 321 ln. 85	(a)
26	Account 561.2	5,212,556					FF1 page 321 ln. 86	(a)
27	Account 561.3	2,238,612					FF1 page 321 ln. 87	(a)
28	Account 561.4	7,157,291					FF1 page 321 ln. 88	(a)
29	O&M (line 22 - lines 23 to 28)	37,849,988		2.0010%	Note 2	757,378		(a)
	Transmission-related Administrative and General							
30	Administrative and General	37,202,294	Note 4				FF1 page 320 ln. 197 b, footnote	(a)
31	**less:** Property Insurance (#924)	763,857	Note 4				FF1 Page 320 ln. 185 b, footnote	(a)
32	**less:** Regulatory Commission Expenses (#928)	2,749,411	Note 4				FF1 page 320 ln. 189 b, footnote	(a)
33	**less:** General Advertising Expense (#930.1)	10,766	Note 4				FF1 page 320 ln. 191 b, footnote	(a)
34	Subtotal (line 30 - lines 31 to 33)	33,678,260		2.0010%	Note 2	673,902		(a)
35	**plus:** Property Insurance	1,413,419		0.7386%	Note 3	10,440	FF1 page 323 ln. 185	(a)
36	**plus:** Trans. Regulatory Comm. Exp.	2,749,411		2.0010%	Note 2	55,016	FF1 page 320 ln. 189 b, footnote	(a)
37	**plus:** Trans. Related General Advertising Expense	10,766		2.0010%	Note 2	215	FF1 page 320 ln. 191 b, footnote	(a)
38	**plus:** Trans. Related Public Education Expense	-				-	FF1 page 114 ln. 49, footnote	(a)
39	**plus:** Trans. Merger-Related Costs	7,153,326		2.0010%		143,138	Exhibit No. ES-220, Page 1 of 8, Line 2(B)	(b)
40	Total A&G (sum of lines 34 to 38)	45,005,182				882,711		(b)
41	Transmission Related Taxes and Fees	9,854,673		2.0010%	Note 2	197,192	Note 5	(a)

Note 1: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.
Note 5: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment B.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Glenbrook Cables
Sheet 1a

Line No.	(A)	Attachment I Reference Section:	(B)	(C) Source	(D) Notes
	I. INVESTMENT BASE				
1	Transmission Plant	II(A)(1)(a)	2,644,161	Sheet 2, Line 5	(a)
2	Transmission Plant Held for Future Use	II(A)(1)(b)	31,396,972	Sheet 2, Line 6	(a)
3	Accumulated Depreciation	II(A)(1)(c)	353,497	Sheet 2, Line 11	(a)
4	Accumulated Deferred Income Taxes	II(A)(1)(d)	323,209	Sheet 2, Line 12	(a)
5	Loss On Reacquired Debt	II(A)(1)(e)	3,969	Sheet 2, Line 13	(a)
6	Other Regulatory Assets	II(A)(1)(f)	6,102	Sheet 2, Line 14	(b)
7	Net Investment (Line 1+2-3-4+5)		33,374,498		(b)
8	Prepayments	II(A)(1)(g)	16,622	Sheet 2, Line 15	(a)
9	Materials & Supplies	II(A)(1)(h)	30,813	Sheet 2, Line 16	(a)
10	Cash Working Capital	II(A)(1)(i)	8,437	Sheet 2, Line 23	(b)
11	Total Investment Base (Line 6+7+8+9)		33,430,370		(b)
	II. REVENUE REQUIREMENTS				
12	Investment Return and Income Taxes	II(A)	4,125,125	Sheet 4a, Line 15(4)	(b)
13	Depreciation Expense	II(B)	63,152	Sheet 8, Line 5	(a)
14	Amortization of Loss on Reacquired Debt	II(C)	413	Sheet 8, Line 6	(a)
15	Investment Tax Credit	II(D)	(476)	Sheet 8, Line 7	(a)
16	Property Tax Expense	II(E)	38,063	Sheet 8, Line 8	(a)
17	Payroll Tax Expense	II(F)	275	Sheet 8, Line 21	(a)
18	Operation & Maintenance Expense	II(G)	32,286	Sheet 8, Line 29	(a)
19	Administrative & General Expense	II(H)	37,629	Sheet 8, Line 40	(b)
20	Support Expenses	II(I)	-		(a)
21	Transmission Related Taxes and Fees	II(J)	8,406	Sheet 8, Line 41	(a)
22	Total Revenue Requirements (Line 11 thru 20)		4,304,873		(b)

Note:
Investment Return and Income Taxes (line 11 above) was calculated based on the Total Investment Base at 11.07% ROE, plus the Localized Post-2003 PTF Transmission Base (lines 1-3-4) at the .67% capped Incremental ROE.

Notes:

(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247

(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Glenbrook Cables
Sheet 2

Line No.	(A)	(B) Trans. Related Average		(C) Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Transmission Plant							
1	Localized Transmission Plant					2,570,000	Sheet 3, Line 17	(a)
2	Transmission General Plant	102,812,641	Note 4				FF1 page 204 ln. 96, footnote	(a)
3	Less: Convex-related General Plant	15,870,872					Note 1	(a)
4	Subtotal: General Plant, net of Convex (line 2 - 3)	86,941,769		0.0853%	Note 2	74,161		(a)
5	Total (line 1+4)					2,644,161		(a)
6	Localized Transmission Plant Held for Future Use					31,396,972		(a)
	Transmission Accumulated Depreciation							
7	Localized Transmission Accum. Depreciation					334,418	Sheet 9, Line 17(I)	(a)
8	General Plant Accum. Depreciation	26,085,325	Note 4				FF1 page 219 ln. 28, footnote	(a)
9	Less: Convex-related General Plant Acc Depr	3,717,252					Note 1	(a)
10	Subtotal: General Plant A/D, net of Convex (line 8-9)	22,368,074		0.0853%	Note 2	19,080		(a)
11	Total (line 7+10)					353,497		(a)
12	Transmission Accumulated Deferred Taxes					323,209	Sheet 10, Line 32	(a)
13	Unam. Loss on Reacquired Debt (189)	12,599,425		0.0315%	Note 3	3,969	FF1 page 111 ln. 81	(a)
14	Localized Transmission Other Regulatory Assets	7,153,326		0.0853%		6,102	Exhibit No. ES-220, Page 1 of 8, Line 4(B)	(b)
15	Transmission Prepayments (165)	19,487,085	Note 4	0.0853%	Note 2	16,622	FF1 page 110 ln. 57, footnote	(a)
15	Transmission Materials and Supplies	36,123,136		0.0853%	Note 2	30,813	FF1 page 227 ln. 8	(a)
	Cash Working Capital							
16	Localized Operation & Maintenance Expense					32,286	Sheet 8, Line 29	(a)
17	Localized Administrative & General Expense					37,629	Sheet 8, Line 40	(c)
18	Subtotal (line 16+17)					69,915		(c)
19	12.5% allowance					0.125	x 45 / 360	(a)
20	Total current Year End (line 18*19)					8,739		(c)
21	Prior Year End Cash Working Capital					8,135	Note 1	(a)
22	Average Cash Working Capital [(line 20+21)/2]					8,437		(c)

Note 1: Reflects actual information per Eversource's accounting records.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset
(c) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Glenbrook Cables
Sheet 4a

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559	Note 2	46.27%	5.36%	Note 2	2.48%		
2	PREFERRED STOCK	$ 116,842,775		2.14%	4.80%		0.10%	0.10%	
3	COMMON EQUITY	$ 2,820,159,065		51.59%	11.07%	Note 1	5.71%	5.71%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399		100.00%			8.29%	5.81%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 8.29% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate)) / Total Inv. Base)) * Federal Income Tax Rate)

Line		R.O.E.		Total Inv. (Tax Credit)		Eq. AFUDC of Deprec. Exp.		Total Inv. Base		Federal Corporate Tax Rate	
	Source:	Line 4, Col. (5)		Sheet 8, Line 7		Sheet 6, Line 1		Sheet 1, Line 10		Federal Corporate Tax Rate	
6	= ((	5.81%	+ ((	(476)	+	1,968	) /	33,430,370	)) *	35.00%	)
7			(	1	-	35.00% Federal Corporate Tax Rate	)				
8	=	3.1309%									

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate)) / Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)

Line		R.O.E.		Total Inv. (Tax Credit)		Eq. AFUDC of Deprec. Exp.		Total Inv. Base		Federal Income Tax		State Income Tax Rate	
	Source:	Line 4, Col. (5)		Sheet 8, Line 7		Sheet 6, Line 1		Sheet 1, Line 10		Line 8, Col. (1)		Connecticut Corporate Tax Rate	
9	= ((	5.81%	+ ((	(476)	+	1,968	) /	33,430,370	) +	3.1309%	) *	9.00%	)
10			(	1	-	9.00% Connecticut Corporate Tax Rate	)						
11	=	0.8847%											

12 (a)+(b)+(c) **Cost of Capital Rate** = 12.3056%

Line			
13	INVESTMENT BASE	33,430,370	Sheet 1, Line 10
14			
15	x Cost of Capital Rate	12.3056%	Line 12, Col. (1)
16	= Investment Return and Income Taxes	$ 4,113,808	

Total Investment Return and Income Taxes

@11.07%	$ 4,113,808	Line 16, Col. (1)
@.67%	$ 11,317	Sheet 5a, Line 17
	$ 4,125,125	To Sheet 1a, Line 11

Note 1: ROE per FERC Order in Docket No. ER11-66 dated October 16, 2014.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes:

(1) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Glenbrook Cables

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559	Note 2	46.27%					
2	PREFERRED STOCK	$ 116,842,775		2.14%					
3	COMMON EQUITY	$ 2,820,159,065		51.59%	0.50%	Note 1	0.26%	0.26%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399		100.00%			0.26%	0.26%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.26% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate) / Total Inv. Base)) * Federal Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Federal Corporate Tax Rate

6 = ((0.26% + ((0 + 0) / 33,430,370)) * 35.00%)
7 (1 - 35.00%) Federal Corporate Tax Rate

8 = 0.1400%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate) / Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Line 8, Col. (1); Connecticut Corporate Tax Rate

9 = ((0.26% + ((0 + 0) / 33,430,370) + 0.1400%) * 9.00%)
10 (1 - 9.00%) Connecticut Corporate Tax Rate

11 = 0.0396%

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.4396%

13 INVESTMENT BASE 33,430,370 Line 16, Col. (4)

14 x Cost of Capital Rate 0.4396% Line 12, Col. (1)

15 = Investment Return and Income Taxes $ 146,960 to Sheet 4a, Line 14(4)

Note 1: CAP on ROE incentives per FERC Order in Docket No. EL11-66 dated March 3, 2015.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.

Notes:

(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-224, Schedule 1, Page 2 of 4, Line 18

(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Glenbrook Cables
Sheet 8

Line No.	(A)	(B) Year End		(C) Localized Trans. Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Depreciation Expense							
1	Transmission Depreciation					59,851	Sheet 9, Line 19	(a)
2	General Depreciation	4,980,574	Note 4				FF1 page 336 ln. 10, footnote	(a)
3	*less:* Convex-related General Plant Depreciation Expense	1,110,693					Note 1	(a)
4	Subtotal: General Plant Depr Exp, net of Convex (line 2-3)	3,869,881		0.0853%	Note 2	3,301		(a)
5	Total (line 1+4)					63,152		(a)
6	Amortization of Loss on Reacquired Debt	1,309,927		0.0315%	Note 3	413	FF1 page 117 ln. 64	(a)
7	Amortization of Investment Tax Credits	1,511,975		0.0315%	Note 3	476	FF1 page 266 ln. 8 (f)	(a)
8	Property Taxes	120,836,131		0.0315%	Note 3	38,063	FF1 page 263 ln. 24i & 25i	(a)
	Payroll Tax Expense							
9	Federal Unemployment	5,226					FF1 page 262 ln. 3i, footnote	(a)
10	FICA	233,351					FF1 page 262 ln. 5i, footnote	(a)
11	Medicare	65,613					FF1 page 262 ln. 9i, footnote	(a)
12	CT Unemployment	16,786					FF1 page 262 ln. 15i, footnote	(a)
13	MA Unemployment	(285)					FF1 page 262 ln. 32i, footnote	(a)
14	MA Universal Health	64					FF1 page 262 ln. 33i, footnote	(a)
15	NH Unemployment	1,754					FF1 page 262.1 ln. 4i, footnote	(a)
16	NJ Unemployment	-					FF1 page 262 footnote	(a)
17	DC Unemployment	11					FF1 page 262.1 ln. 14i, footnote	(a)
18	FL Unemployment	1					FF1 page 262.1 ln. 18i, footnote	(a)
19	MI Unemployment	6					FF1 page 262.1 ln. 22i, footnote	(a)
20	NY Unemployment	-					FF1 page 262.1 ln. 10i, footnote	(a)
21	Total (Line 9 to 20)	322,527	Note 4	0.0853%	Note 2	275		
	Transmission Operation and Maintenance							
22	Operation and Maintenance	77,432,007					FF1 page 321 ln. 112	(a)
23	Transmission of Electricity by Others - #565	21,727,966					FF1 page 321 ln. 96	(a)
24	Load Dispatching - #561	-					FF1 page 321 ln. 84	(a)
25	Account 561.1	3,245,594					FF1 page 321 ln. 85	(a)
26	Account 561.2	5,212,556					FF1 page 321 ln. 86	(a)
27	Account 561.3	2,238,612					FF1 page 321 ln. 87	(a)
28	Account 561.4	7,157,291					FF1 page 321 ln. 88	(a)
29	O&M (line 22 - lines 23 to 28)	37,849,988		0.0853%	Note 2	32,286		(a)
	Transmission-related Administrative and General							
30	Administrative and General	37,202,294	Note 4				FF1 page 320 ln. 197 b, footnote	(a)
31	less: Property Insurance (#924)	763,857	Note 4				FF1 Page 320 ln. 185 b, footnote	(a)
32	less: Regulatory Commission Expenses (#928)	2,749,411	Note 4				FF1 page 320 ln. 189 b, footnote	(a)
33	less: General Advertising Expense (#930.1)	10,766	Note 4				FF1 page 320 ln. 191 b, footnote	(a)
34	Subtotal (line 30 - lines 31 to 33)	33,678,260		0.0853%	Note 2	28,728		(a)
35	plus: Property Insurance	1,413,419		0.0315%	Note 3	445	FF1 page 323 ln. 185	(a)
36	plus: Trans. Regulatory Comm. Exp.	2,749,411		0.0853%	Note 2	2,345	FF1 page 320 ln. 189 b, footnote	(a)
37	plus: Trans. Related General Advertising Expense	10,766		0.0853%	Note 2	9	FF1 page 320 ln. 191 b, footnote	(a)
38	plus: Trans. Related Public Education Expense	-				-	FF1 page 114 ln. 49, footnote	(a)
39	plus: Trans. Merger-Related Costs	7,153,326		0.0853%		6,102	Exhibit No. ES-220, Page 1 of 8, Line 2(B)	(b)
40	Total A&G (sum of lines 34 to 38)	45,005,182				37,629		(b)
41	Transmission Related Taxes and Fees	9,854,673		0.0853%	Note 2	8,406	Note 5	(a)

Note 1: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.
Note 5: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment B.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 1a

Line No.	(A)	Attachment I Reference Section:	(B)	(C) Source	(D) Notes
	I. INVESTMENT BASE				
1	Transmission Plant	II(A)(1)(a)	3,169,795	Sheet 2, Line 5	(a)
2	Transmission Plant Held for Future Use	II(A)(1)(b)	-	Sheet 2, Line 6	(a)
3	Accumulated Depreciation	II(A)(1)(c)	116,694	Sheet 2, Line 11	(a)
4	Accumulated Deferred Income Taxes	II(A)(1)(d)	265,445	Sheet 2, Line 12	(a)
5	Loss On Reacquired Debt	II(A)(1)(e)	4,750	Sheet 2, Line 13	(a)
6	Other Regulatory Assets	II(A)(1)(f)	7,318	Sheet 2, Line 14	(b)
7	Net Investment (Line 1+2-3-4+5)		2,799,724		(b)
8	Prepayments	II(A)(1)(g)	19,935	Sheet 2, Line 15	(a)
9	Materials & Supplies	II(A)(1)(h)	36,954	Sheet 2, Line 16	(a)
10	Cash Working Capital	II(A)(1)(i)	5,241	Sheet 2, Line 23	(b)
11	Total Investment Base (Line 6+7+8+9)		2,861,854		(b)
	II. REVENUE REQUIREMENTS				
12	Investment Return and Income Taxes	II(A)	369,419	Sheet 4a, Line 15(4)	(b)
13	Depreciation Expense	II(B)	78,802	Sheet 8, Line 5	(a)
14	Amortization of Loss on Reacquired Debt	II(C)	494	Sheet 8, Line 6	(a)
15	Investment Tax Credit	II(D)	(570)	Sheet 8, Line 7	(a)
16	Property Tax Expense	II(E)	45,555	Sheet 8, Line 8	(a)
17	Payroll Tax Expense	II(F)	330	Sheet 8, Line 21	(a)
18	Operation & Maintenance Expense	II(G)	38,721	Sheet 8, Line 29	(a)
19	Administrative & General Expense	II(H)	45,128	Sheet 8, Line 40	(b)
20	Support Expenses	II(I)	-		(a)
21	Transmission Related Taxes and Fees	II(J)	10,081	Sheet 8, Line 41	(a)
22	Total Revenue Requirements (Line 11 thru 20)		587,960		(b)

Note:
Investment Return and Income Taxes (line 11 above) was calculated based on the Total Investment Base at 11.07% ROE, plus the Localized PTF Transmission Base (lines 1-3-4) at the .67% capped Incremental ROE.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 2

Line No.	(A)	(B) Trans. Related Average		(C) Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Transmission Plant							
1	Localized Transmission Plant					3,080,854	Sheet 3, Line 18	(a)
2	Transmission General Plant	102,812,641	Note 4				FF1 page 204 ln. 96, footnote	(a)
3	Less: Convex-related General Plant	15,870,872					Note 1	(a)
4	Subtotal: General Plant, net of Convex (line 2 - 3)	86,941,769		0.1023%	Note 2	88,941		(a)
5	Total (line 1+4)					3,169,795		(a)
6	Localized Transmission Plant Held for Future Use					-		(a)
	Transmission Accumulated Depreciation							
7	Localized Transmission Accum. Depreciation					93,811	Sheet 9, Line 10(I)	(a)
8	General Plant Accum. Depreciation	26,085,325	Note 4				FF1 page 219 ln. 28, footnote	(a)
9	Less: Convex-related General Plant Acc Depr	3,717,252					Note 1	(a)
10	Subtotal: General Plant A/D, net of Convex (line 8-9)	22,368,074		0.1023%	Note 2	22,883		(a)
11	Total (line 7+10)					116,694		(a)
12	Transmission Accumulated Deferred Taxes					265,445	Sheet 10, Line 46	(a)
13	Unam. Loss on Reacquired Debt (189)	12,599,425		0.0377%	Note 3	4,750	FF1 page 111 ln. 81	(a)
14	Localized Transmission Other Regulatory Assets	7,153,326		0.1023%		7,318	Exhibit No. ES-220, Page 1 of 8, Line 4(B)	(b)
15	Transmission Prepayments (165)	19,487,085	Note 4	0.1023%	Note 2	19,935	FF1 page 110 ln. 57, footnote	(a)
16	Transmission Materials and Supplies	36,123,136		0.1023%	Note 2	36,954	FF1 page 227 ln. 8	(a)
	Cash Working Capital							
17	Localized Operation & Maintenance Expense					38,721	Sheet 8, Line 29	(a)
18	Localized Administrative & General Expense					45,128	Sheet 8, Line 40	(c)
19	Subtotal (line 16+17)					83,849		(c)
20	12.5% allowance					0.125	x 45 / 360	(a)
21	Total current Year End (line 18*19)					10,481		(c)
22	Prior Year End Cash Working Capital					-	Note 1	(a)
23	Average Cash Working Capital [(line 20+21)/2]					5,241		(c)

Note 1: Reflects actual information per Eversource's accounting records.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.

Notes:

(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset
(c) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 4a

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559	Note 2	46.27%	5.36%	Note 2	2.48%		
2	PREFERRED STOCK	$ 116,842,775		2.14%	4.80%		0.10%	0.10%	
3	COMMON EQUITY	$ 2,820,159,065		51.59%	11.07%	Note 1	5.71%	5.71%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399		100.00%			8.29%	5.81%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 8.29% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate)) / Total Inv. Base)) * Federal Income Tax Rate)

Source: Line 4, Col. (5); Sheet 8, Line 7; Sheet 6, Line 1; Sheet 1, Line 10; Federal Corporate Tax Rate

6 = ((5.81% + (((570) + 2,360) / 2,861,854)) * 35.00%)
7 (1 - 35.00%) Federal Corporate Tax Rate

8 = 3.1621%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate)) / Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)

Source: Line 4, Col. (5); Sheet 8, Line 7; Sheet 6, Line 1; Sheet 1, Line 10; Line 8, Col. (1); Connecticut Corporate Tax Rate

9 = ((5.81% + (((570) + 2,360) / 2,861,854) + 3.1621%) * 9.00%)
10 (1 - 9.00%) Connecticut Corporate Tax Rate

11 = 0.8935%

12 (a)+(b)+(c) **Cost of Capital Rate** = 12.3456%

13	INVESTMENT BASE	2,861,854	Sheet 1, Line 10
14			
15	x Cost of Capital Rate	12.3456%	Line 12, Col. (1)
16	= Investment Return and Income Taxes	$ 353,313	

Total Investment Return and Income Taxes		
@11.07%	$ 353,313	Line 16, Col. (1)
@.67%	$ 16,106	Sheet 5a, Line 17
	$ 369,419	To Sheet 1a, Line 11

Note 1: ROE per FERC Order in Docket No. ER11-66 dated October 16, 2014.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes:

(1) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 5a

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559	Note 2	46.27%					
2	PREFERRED STOCK	$ 116,842,775		2.14%					
3	COMMON EQUITY	$ 2,820,159,065		51.59%	0.50%	Note 1	0.26%	0.26%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399		100.00%			0.26%	0.26%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.26% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate) Total Inv. Base)) * Federal Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Federal Corporate Tax Rate

6 = ((0.26% + ((0 + 0) / 2,861,854)) * 35.00%)

7 (1 - 35.00%) Federal Corporate Tax Rate

8 = 0.1400%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate) Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Line 8, Col. (1); Connecticut Corporate Tax Rate

9 = ((0.26% + ((0 + 0) / 2,861,854) + 0.1400%) * 9.00%)

10 (1 - 9.00%) Connecticut Corporate Tax Rate

11 = 0.0396%

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.4396%

13 INVESTMENT BASE 2,861,854 Line 16, Col. (4)

14 x Cost of Capital Rate 0.4396% Line 12, Col. (1)

15 = Investment Return and Income Taxes $ 12,581 to Sheet 4a, Line 14(4)

Note 1: CAP on ROE incentives per FERC Order in Docket No. EL11-66 dated March 3, 2015.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.

Notes:

(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-224, Schedule 1, Page 2 of 4, Line 18
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 8

Line No.	(A)	(B) Year End		(C) Localized Trans. Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Depreciation Expense							
1	Transmission Depreciation					74,843	Sheet 9, Line 12	(a)
2	General Depreciation	4,980,574	Note 4				FF1 page 336 ln. 10, footnote	(a)
3	*less:* Convex-related General Plant Depreciation Expense	1,110,693					Note 1	(a)
4	Subtotal: General Plant Depr Exp, net of Convex (line 2-3)	3,869,881		0.1023%	Note 2	3,959		(a)
5	Total (line 1+4)					78,802		(a)
6	Amortization of Loss on Reacquired Debt	1,309,927		0.0377%	Note 3	494	FF1 page 117 ln. 64	(a)
7	Amortization of Investment Tax Credits	1,511,975		0.0377%	Note 3	570	FF1 page 266 ln. 8 (f)	(a)
8	Property Taxes	120,836,131		0.0377%	Note 3	45,555	FF1 page 263 ln. 24i & 25i	(a)
	Payroll Tax Expense							
9	Federal Unemployment	5,226					FF1 page 262 ln. 3i, footnote	(a)
10	FICA	233,351					FF1 page 262 ln. 5i, footnote	(a)
11	Medicare	65,613					FF1 page 262 ln. 9i, footnote	(a)
12	CT Unemployment	16,786					FF1 page 262 ln. 15i, footnote	(a)
13	MA Unemployment	(285)					FF1 page 262 ln. 32i, footnote	(a)
14	MA Universal Health	64					FF1 page 262 ln. 33i, footnote	(a)
15	NH Unemployment	1,754					FF1 page 262.1 ln. 4i, footnote	(a)
16	NJ Unemployment	-					FF1 page 262 footnote	(a)
17	DC Unemployment	11					FF1 page 262.1 ln. 14i, footnote	(a)
18	FL Unemployment	1					FF1 page 262.1 ln. 18i, footnote	(a)
19	MI Unemployment	6					FF1 page 262.1 ln. 22i, footnote	(a)
20	NY Unemployment	-					FF1 page 262.1 ln. 10i, footnote	(a)
21	Total (Line 9 to 20)	322,527	Note 4	0.1023%	Note 2	330		
	Transmission Operation and Maintenance							
22	Operation and Maintenance	77,432,007					FF1 page 321 ln. 112	(a)
23	Transmission of Electricity by Others - #565	21,727,966					FF1 page 321 ln. 96	(a)
24	Load Dispatching - #561	-					FF1 page 321 ln. 84	(a)
25	Account 561.1	3,245,594					FF1 page 321 ln. 85	(a)
26	Account 561.2	5,212,556					FF1 page 321 ln. 86	(a)
27	Account 561.3	2,238,612					FF1 page 321 ln. 87	(a)
28	Account 561.4	7,157,291					FF1 page 321 ln. 88	(a)
29	O&M (line 22 - lines 23 to 28)	37,849,988		0.1023%	Note 2	38,721		(a)
	Transmission-related Administrative and General							
30	Administrative and General	37,202,294	Note 4				FF1 page 320 ln. 197 b, footnote	(a)
31	less: Property Insurance (#924)	763,857	Note 4				FF1 Page 320 ln. 185 b, footnote	(a)
32	less: Regulatory Commission Expenses (#928)	2,749,411	Note 4				FF1 page 320 ln. 189 b, footnote	(a)
33	less: General Advertising Expense (#930.1)	10,766	Note 4				FF1 page 320 ln. 191 b, footnote	(a)
34	Subtotal (line 30 - lines 31 to 33)	33,678,260		0.1023%	Note 2	34,453		(a)
35	plus: Property Insurance	1,413,419		0.0377%	Note 3	533	FF1 page 323 ln. 185	(a)
36	plus: Trans. Regulatory Comm. Exp.	2,749,411		0.1023%	Note 2	2,813	FF1 page 320 ln. 189 b, footnote	(a)
37	plus: Trans. Related General Advertising Expense	10,766		0.1023%	Note 2	11	FF1 page 320 ln. 191 b, footnote	(a)
38	plus: Trans. Related Public Education Expense	-				-	FF1 page 114 ln. 49, footnote	(a)
39	plus: Trans. Merger-Related Costs	7,153,326		0.1023%		7,318	Exhibit No. ES-220, Page 1 of 8, Line 2(B)	(b)
40	Total A&G (sum of lines 34 to 38)	45,005,182				45,128		(b)
41	Transmission Related Taxes and Fees	9,854,673		0.1023%	Note 2	10,081	Note 5	(a)

Note 1: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.
Note 5: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment B.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Western Massachusetts Electric Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 1a

Line No.	(A)	Attachment I Reference Section:	(B)	(C) Source	(D) Notes
	I. INVESTMENT BASE				
1	Transmission Plant	II(A)(1)(a)	7,316,798	Sheet 2, Line 5	(a)
2	Transmission Plant Held for Future Use	II(A)(1)(b)	-	Sheet 2, Line 6	(a)
3	Accumulated Depreciation	II(A)(1)(c)	290,421	Sheet 2, Line 11	(a)
4	Accumulated Deferred Income Taxes	II(A)(1)(d)	603,776	Sheet 2, Line 12	(a)
5	Loss On Reacquired Debt	II(A)(1)(e)	2,313	Sheet 2, Line 13	(a)
6	Other Regulatory Assets	II(A)(1)(f)	16,636	Sheet 2, Line 14	(b)
7	Net Investment (Line 1+2-3-4+5)		6,441,550		(b)
8	Prepayments	II(A)(1)(g)	5,502	Sheet 2, Line 15	(a)
9	Materials & Supplies	II(A)(1)(h)	26,259	Sheet 2, Line 16	(a)
10	Cash Working Capital	II(A)(1)(i)	8,761	Sheet 2, Line 23	(b)
11	Total Investment Base (Line 6+7+8+9)		6,482,072		(b)
	II. REVENUE REQUIREMENTS				
12	Investment Return and Income Taxes	II(A)	781,439	Sheet 4a, Line 15(4)	(b)
13	Depreciation Expense	II(B)	184,929	Sheet 8, Line 5	(a)
14	Amortization of Loss on Reacquired Debt	II(C)	323	Sheet 8, Line 6	(a)
15	Investment Tax Credit	II(D)	(154)	Sheet 8, Line 7	(a)
16	Property Tax Expense	II(E)	144,952	Sheet 8, Line 8	(a)
17	Payroll Tax Expense	II(F)	157	Sheet 8, Line 21	(a)
18	Operation & Maintenance Expense	II(G)	54,519	Sheet 8, Line 29	(a)
19	Administrative & General Expense	II(H)	85,648	Sheet 8, Line 39	(b)
20	Support Expenses	II(I)	-		(a)
21	Transmission Related Taxes and Fees	II(J)	177	Sheet 8, Line 40	(a)
22	Total Revenue Requirements (Line 11 thru 20)		1,251,990		(b)

Note:
Investment Return and Income Taxes (line 11 above) was calculated based on the Total Investment Base at 11.07% ROE, plus the Localized PTF Transmission Base (lines 1-3-4) at the .67% capped Incremental ROE.

Notes:

(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247

(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

Western Massachusetts Electric Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 2

Line No.	(A)	(B) Trans. Related Average		(C) Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Transmission Plant							
1	Localized Transmission Plant					7,159,714	Sheet 3, Line 33	(a)
2	Transmission General Plant	18,348,753	Note 4	0.8561%	Note 2	157,084	FF1 page 204 ln. 96, footnote	(a)
3	Total (line 1+2)					7,316,798		(a)
4	Localized Transmission Plant Held for Future Use					-		(a)
	Transmission Accumulated Depreciation							
5	Localized Transmission Accum. Depreciation					256,419	Sheet 9, Line 27(I)	(a)
6	General Plant Accum.Depreciation	3,971,742	Note 4	0.8561%	Note 2	34,002	FF1 page 219 ln. 28, footnote	(a)
7	Total (line 5+6)					290,421		(a)
8								
9	Transmission Accumulated Deferred Taxes					603,776	Sheet 10, Line 46	(a)
10	Unam. Loss on Reacquired Debt (189)	533,928		0.4332%	Note 3	2,313	FF1 page 111 ln. 81	(a)
11	Localized Transmission Other Regulatory Assets	1,943,209		0.8561%		16,636	Exhibit No. ES-220, Page 4 of 8, Line 4(B)	(b)
12	Transmission Prepayments (165)	642,737	Note 4	0.8561%	Note 2	5,502	FF1 page 110 ln. 57, footnote	(a)
13	Transmission Materials and Supplies	3,067,304		0.8561%	Note 2	26,259	FF1 page 227 ln. 8	(a)
	Cash Working Capital							
14	Localized Operation & Maintenance Expense					54,519	Sheet 8, Line 28	(a)
15	Localized Administrative & General Expense					85,648	Sheet 8, Line 39	(c)
16	Subtotal (line 13+14)					140,167		(c)
17	12.5% allowance					0.125	x 45 / 360	(a)
18	Total current Year End (line 15*16)					17,521		(c)
19	Prior Year End Cash Working Capital					-		(d)
20	Average Cash Working Capital [(line 17+18)/2]					8,761		(c)

Note 1: Reflects actual information per Eversource's accounting records.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset
(c) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Western Massachusetts Electric Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 4a

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 568,072,183	Note 2	49.54%	4.31%	Note 2	2.14%		
2	PREFERRED STOCK	$ -		0.00%	0.00%		0.00%	0.00%	
3	COMMON EQUITY	$ 578,634,319		50.46%	11.07%	Note 1	5.59%	5.59%	
4	TOTAL INVESTMENT RETURN	$ 1,146,706,502		100.00%			7.73%	5.59%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 7.73% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / Total Inv. Base)) * Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

Source: Line 4, Col. (5); Sheet 8, Line 7; Sheet 6, Line 1; Sheet 1, Line 10; Federal Corporate Tax Rate

6 = ((5.59% + (((154) + 1,593) / 6,482,072)) * 35.00%)
7 (1 - 35.00%) Federal Corporate Tax Rate

8 = 3.0220%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / Total Inv. Base) + Federal Income Tax) * State Income Tax Rate) / (1 - State Income Tax Rate)

Source: Line 4, Col. (5); Sheet 8, Line 7; Sheet 6, Line 1; Sheet 1, Line 10; Line 8, Col. (1); Massachusetts Corporate Tax Rate

9 = ((5.59% + (((154) + 1,593) / 6,482,072) + 3.0220%) * 8.00%)
10 (1 - 8.00%) Massachusetts Corporate Tax Rate

11 = 0.7508%

12 (a)+(b)+(c) **Cost of Capital Rate** = 11.5028%

13	INVESTMENT BASE	6,482,072	Sheet 1, Line 10
14			
15	x Cost of Capital Rate	11.5028%	Line 12, Col. (1)
16	= Investment Return and Income Taxes	$ 745,620	

Total Investment Return and Income Taxes		
@11.07%	$ 745,620	Line 16, Col. (1)
@.67%	$ 35,819	Sheet 5, Line 17
	$ 781,439	To Sheet 1a, Line 11

Note 1: ROE per FERC Order in Docket No. ER04-157 dated March 24, 2008.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes:

(1) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Western Massachusetts Electric Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 568,072,183	Note 2	49.54%					
2	PREFERRED STOCK	$ -		0.00%					
3	COMMON EQUITY	$ 578,634,319		50.46%	0.50%	Note 1	0.25%	0.25%	
4	TOTAL INVESTMENT RETURN	$ 1,146,706,502		100.00%			0.25%	0.25%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.25% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / Total Inv. Base)) * Federal Income Tax Rate)
(1 - Federal Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Federal Corporate Tax Rate
6 = ((0.25% + ((0 + 0) / 6,482,072)) * 35.00%)
7 (1 - 35.00%) Federal Corporate Tax Rate

8 = 0.1346%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)
(1 - State Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Line 8, Col. (1); Massachusetts Corporate Tax Rate
9 = ((0.25% + ((0 + 0) / 6,482,072) + 0.1346%) * 8.00%)
10 (1 - 8.00%) Massachusetts Corporate Tax Rate

11 = 0.0334%

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.4180%

13 INVESTMENT BASE 6,482,072 Line 16, Col. (4)

14 x Cost of Capital Rate 0.4180% Line 12, Col. (1)

15 = Investment Return and Income Taxes $ 27,095 to Sheet 4a, Line 14(4)

Note 1: CAP on ROE incentives per FERC Order in Docket No. EL11-66 dated March 3, 2015.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.

Notes:

(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-224, Schedule 1, Page 2 of 4, Line 18
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Western Massachusetts Electric Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 8

Line No.	(A)	(B) Year End		(C) Localized Trans. Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Depreciation Expense							
1	Transmission Depreciation					178,169	Sheet 9, Line 29	(a)
2	General Depreciation	789,658	Note 4	0.8561%	Note 2	6,760	FF1 page 336 ln. 10, footnote	(a)
3	Total (line 1+4)					184,929		(a)
4								(a)
								(a)
5	Amortization of Loss on Reacquired Debt	74,501		0.4332%	Note 3	323	FF1 pg 117 ln. 64	
								(a)
6	Amortization of Investment Tax Credits	35,604		0.4332%	Note 3	154	FF1 page 266 ln. 8(f), footnote	
								(a)
7	Property Taxes	33,460,690		0.4332%	Note 3	144,952	FF1 page 263 ln. 31i & 32i	
								(a)
	Payroll Tax Expense							
8	Federal Unemployment	283					FF1 page 262 ln. 3i, footnote	
9	FICA	13,202					FF1 page 262 ln. 5i, footnote	(a)
10	Medicare	3,757					FF1 page 262 ln. 9i, footnote	(a)
11	CT Unemployment	852					FF1 page 262 ln. 13i, footnote	(a)
12	MA Unemployment	69					FF1 page 262 ln. 22i, footnote	(a)
13	MA Universal Health	19					FF1 page 262 ln. 27i, footnote	(a)
14	NH Unemployment	108					FF1 page 262 ln. 37i, footnote	(a)
15	NJ Unemployment	-					FF1 page 262, footnote	(a)
16	DC Unemployment	1					FF1 page 262.1 ln. 6i, footnote	(a)
17	FL Unemployment	-					FF1 page 262, footnote	(a)
18	MI Unemployment	-					FF1 page 262, footnote	(a)
19	NY Unemployment	-					FF1 page 262, footnote	(a)
20	Total (Line 9 to 20)	18,291	Note 4	0.8561%	Note 2	157		(a)
	Transmission Operation and Maintenance							
21	Operation and Maintenance	20,725,279					FF1 page 321 ln. 112	
22	Transmission of Electricity by Others - #565	13,174,678					FF1 page 321 ln. 96	(a)
23	Load Dispatching - #561	-					FF1 page 321 ln. 84	(a)
24	Account 561.1	12,368					FF1 page 321 ln. 85	(a)
25	Account 561.2	50,569					FF1 page 321 ln. 86	(a)
26	Account 561.3	13,262					FF1 page 321 ln. 87	(a)
27	Account 561.4	1,106,108					FF1 page 321 ln. 88	(a)
28	O&M (line 22 - lines 23 to 28)	6,368,294		0.8561%	Note 2	54,519		(a)
								(a)
	Transmission-related Administrative and General							
29	Administrative and General	8,041,502	Note 4				FF1 page 320 ln. 197, footnote	(a)
30	less: Property Insurance (#924)	106,141	Note 4				FF1 Page 320 ln. 185 b, footnote	(a)
31	less: Regulatory Commission Expenses (#928)	563,123	Note 4				FF1 page 320 ln. 189 b, footnote	(a)
32	less: General Advertising Expense (#930.1)	2,857	Note 4				FF1 page 320 ln. 191 b, footnote	(a)
33	Subtotal (line 30 - lines 31 to 33)	7,369,381		0.8561%	Note 2	63,089		(a)
34	plus: Property Insurance	248,747		0.4332%	Note 3	1,078	FF1 page 323 ln. 185	(a)
35	plus: Trans. Regulatory Comm. Exp.	563,123		0.8561%	Note 2	4,821	FF1 page 320 ln. 189 b, footnote	(a)
36	plus: Trans. Related General Advertising Expense	2,857		0.8561%	Note 2	24	FF1 page 320 ln. 191 b, footnote	(a)
37	plus: Trans. Related Public Education Expense	-				-	FF1 page 114 ln. 49, footnote	(a)
38	plus: Trans. Merger-Related Costs	1,943,209		0.8561%		16,636	Exhibit No. ES-220, Page 4 of 8, Line 2(B)	(b)
39	Total A&G (sum of lines 34 to 38)	10,127,317				85,648	Exhibit No. ES-220, Page 1 of 8, Line 2	(b)
40	Transmission Related Taxes and Fees	20,627		0.8561%	Note 2	177	Note 5	
								(a)

Note 1: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.
Note 5: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment B.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Exhibit No. ES-226
Schedule 4

Category B Revenue Requirements under the Changed Rates for 2017

Eversource Energy Service Company

CL&P and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I) of the ISO-NE OATT
For the Calendar year 2017

	(A)	(B)	(C)		(D)		(E)		(F)		(G)		(H)=(C)+(D)+(E)+(F)+(G)	
			CL&P								WMECO			
Line	Description	Reference	B-N		M-N		G-C		GSRP		GSRP		Total	
1	2014 Actual Schedule 21-ES, Category B Rev. Req.		$ 19,577,235	(1)	$ 10,340,828	(2)	$ 4,305,285	(3)	$ 589,056	(4)	$ 1,253,948	(5)	$ 36,066,352	
2	Estimated 2015 Plant Additions	(6)	$ -		$ -		$ -		$ -		$ -		$ -	
3	Carrying Charge Factor (CCF)	(6)	0.00%		0.00%		0.00%		0.00%		0.00%			
4	2015 Incremental Estimated Schedule 21-ES, Cat. B Rev. Req.	Line 2 x 3	-		-		-		-		-		$ -	
5	Total Estimated Schedule 21-ES, Cat. B Revenue Requirement for 2015	Line 1 + 4	$ 19,577,235		$ 10,340,828		$ 4,305,285		$ 589,056		$ 1,253,948		$ 36,066,352	
6	Estimated 2016 Plant Additions	(6)	$ -		$ -		$ -		$ -		$ -		$ -	
7	Carrying Charge Factor (CCF)	(6)	0.00%		0.00%		0.00%		0.00%		0.00%			
8	2016 Incremental Estimated Schedule 21-ES, Cat. B Rev. Req.	Line 7 x 8	-		-		-		-		-		$ -	
9	Total Estimated Schedule 21-ES, Cat. B Revenue Requirement for 2016	Line 6 + 9	$ 19,577,235		$ 10,340,828		$ 4,305,285		$ 589,056		$ 1,253,948		$ 36,066,352	(7)

Notes:
(1) Exhibit No. ES-226, Schedule 3, Page 2 of 26, Line 22(B)
(2) Exhibit No. ES-226, Schedule 3, Page 7 of 26, Line 22(B)
(3) Exhibit No. ES-226, Schedule 3, Page 12 of 26, Line 22(B)
(4) Exhibit No. ES-226, Schedule 3, Page 17 of 26, Line 22(B)
(5) Exhibit No. ES-226, Schedule 3, Page 22 of 26, Line 22(B)
(6) These are no forecasted plant additions for Category B
(7) The revenue requirements calculations for the calendar year 2016 (including any forecast for 2016) are used as an estimate for the revenue requirements for 2017, which are used to calculate the revenue impact of the proposed cost recovery.

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Bethel-Norwalk
Sheet 1a

Line No.	(A)	Attachment I Reference Section:	(B)	(C) Source	(D) Notes
	I. INVESTMENT BASE				
1	Transmission Plant	II(A)(1)(a)	125,258,704	Sheet 2, Line 5	(a)
2	Transmission Plant Held for Future Use	II(A)(1)(b)	-	Sheet 2, Line 6	(a)
3	Accumulated Depreciation	II(A)(1)(c)	23,816,817	Sheet 2, Line 11	(a)
4	Accumulated Deferred Income Taxes	II(A)(1)(d)	19,494,337	Sheet 2, Line 12	(a)
5	Loss On Reacquired Debt	II(A)(1)(e)	187,920	Sheet 2, Line 13	(a)
6	Other Regulatory Assets	II(A)(1)(f)	433,567	Sheet 2, Line 14	(b)
7	Net Investment (Line 1+2-3-4+5)		82,569,037		(b)
8	Prepayments	II(A)(1)(g)	787,415	Sheet 2, Line 15	(a)
9	Materials & Supplies	II(A)(1)(h)	1,459,628	Sheet 2, Line 16	(a)
10	Cash Working Capital	II(A)(1)(i)	413,987	Sheet 2, Line 23	(b)
11	Total Investment Base (Line 6+7+8+9)		85,230,067		(b)
	II. REVENUE REQUIREMENTS				
12	Investment Return and Income Taxes	II(A)	11,003,705	Sheet 4a, Line 15(4)	(b)
13	Depreciation Expense	II(B)	3,051,146	Sheet 8, Line 5	(a)
14	Amortization of Loss on Reacquired Debt	II(C)	19,538	Sheet 8, Line 6	(a)
15	Investment Tax Credit	II(D)	(22,551)	Sheet 8, Line 7	(a)
16	Property Tax Expense	II(E)	1,802,271	Sheet 8, Line 8	(a)
17	Payroll Tax Expense	II(F)	13,032	Sheet 8, Line 21	(a)
18	Operation & Maintenance Expense	II(G)	1,529,404	Sheet 8, Line 29	(a)
19	Administrative & General Expense	II(H)	1,782,492	Sheet 8, Line 40	(b)
20	Support Expenses	II(I)	-		(a)
21	Transmission Related Taxes and Fees	II(J)	398,198	Sheet 8, Line 41	(a)
22	Total Revenue Requirements (Line 11 thru 20)		19,577,235		(b)

Note:
Investment Return and Income Taxes (line 11 above) was calculated based on the Total Investment Base at 11.07% ROE, plus the Localized Post-2003 PTF Transmission Base (lines 1-3-4) at the .67% capped Incremental ROE.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Bethel-Norwalk
Sheet 2

Line No.	(A)	(B) Trans. Related Average		(C) Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Transmission Plant							
1	Localized Transmission Plant					121,745,648	Sheet 3, Line 19	(a)
2	Transmission General Plant	102,812,641	Note 4				FF1 page 204 ln. 96, footnote	(a)
3	Less: Convex-related General Plant	15,870,872					Note 1	(a)
4	Subtotal: General Plant, net of Convex (line 2 - 3)	86,941,769		4.0407%	Note 2	3,513,056		(a)
5	Total (line 1+4)					125,258,704		(a)
6	Localized Transmission Plant Held for Future Use					-		(a)
	Transmission Accumulated Depreciation							
7	Localized Transmission Accum. Depreciation					22,912,990	Sheet 9, Line 56(I)	(a)
8	General Plant Accum. Depreciation	26,085,325	Note 4				FF1 page 219 ln. 28, footnote	(a)
9	Less: Convex-related General Plant Acc Depr	3,717,252					Note 1	(a)
10	Subtotal: General Plant A/D, net of Convex (line 8-9)	22,368,074		4.0407%	Note 2	903,827		(a)
11	Total (line 7+10)					23,816,817		(a)
12	Transmission Accumulated Deferred Taxes					19,494,337	Sheet 10, Line 111	(a)
13	Unam. Loss on Reacquired Debt (189)	12,599,425		1.4915%	Note 3	187,920	FF1 page 111 ln. 81	(a)
14	Localized Transmission Other Regulatory Assets	10,729,989		4.0407%		433,567	Exhibit No. ES-220, Page 1 of 8, Line 4(C)	(b)
15	Transmission Prepayments (165)	19,487,085	Note 4	4.0407%	Note 2	787,415	FF1 page 110 ln. 57, footnote	(a)
16	Transmission Materials and Supplies	36,123,136		4.0407%	Note 2	1,459,628	FF1 page 227 ln. 8	(a)
	Cash Working Capital							
17	Localized Operation & Maintenance Expense					1,529,404	Sheet 8, Line 29	(a)
18	Localized Administrative & General Expense					1,782,492	Sheet 8, Line 40	(c)
19	Subtotal (line 16+17)					3,311,896		(c)
20	12.5% allowance					0.125	x 45 / 360	(a)
21	Total current Year End (line 18*19)					413,987		(c)
22	Prior Year End Cash Working Capital					413,987		(d)
23	Average Cash Working Capital [(line 20+21)/2]					413,987		(c)

Note 1: Reflects actual information per Eversource's accounting records.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset
(c) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses
(d) Exhibit No. 226, Schedule 3, Page 3 of 26, Line 21(D)

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Bethel-Norwalk
Sheet 4a

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559	Note 2	46.27%	5.36%	Note 2	2.48%		
2	PREFERRED STOCK	$ 116,842,775		2.14%	4.80%		0.10%	0.10%	
3	COMMON EQUITY	$ 2,820,159,065		51.59%	11.07%	Note 1	5.71%	5.71%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399		100.00%			8.29%	5.81%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 8.29% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / Total Inv. Base)) * Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

Source: Line 4, Col. (5); Sheet 8, Line 7; Sheet 6, Line 1; Sheet 1, Line 10; Federal Corporate Tax Rate

6 = ((5.81% + (((22,551) + 93,235) / 85,230,067)) * 35.00%)
7 (1 - 35.00%) — Federal Corporate Tax Rate

8 = 3.1731%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / Total Inv. Base) + Federal Income Tax) * State Income Tax Rate) / (1 - State Income Tax Rate)

Source: Line 4, Col. (5); Sheet 8, Line 7; Sheet 6, Line 1; Sheet 1, Line 10; Line 8, Col. (1); Connecticut Corporate Tax Rate

9 = ((5.81% + (((22,551) + 93,235) / 85,230,067) + 3.1731%) * 9.00%)
10 (1 - 9.00%) — Connecticut Corporate Tax Rate

11 = 0.8966%

12 (a)+(b)+(c) **Cost of Capital Rate** = 12.3597%

13	INVESTMENT BASE	85,230,067	Sheet 1, Line 10
14			
15	x Cost of Capital Rate	12.3597%	Line 12, Col. (1)
16	= Investment Return and Income Taxes	$ 10,534,181	

Total Investment Return and Income Taxes		
@11.07%	$ 10,534,181	Line 16, Col. (1)
@.67%	$ 469,524	Sheet 5a, Line 17
	$ 11,003,705	To Sheet 1a, Line 11

Note 1: ROE per FERC Order in Docket No. ER11-66 dated October 16, 2014.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes:

(1) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Bethel-Norwalk

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559	Note 2	46.27%					
2	PREFERRED STOCK	$ 116,842,775		2.14%					
3	COMMON EQUITY	$ 2,820,159,065		51.59%	0.50%	Note 1	0.26%	0.26%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399		100.00%			0.26%	0.26%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.26% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / Total Inv. Base)) * Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Federal Corporate Tax Rate

6 = ((0.26% + ((0 + 0) / 85,230,067)) * 35.00%)
7 (1 - 35.00%) Federal Corporate Tax Rate

8 = 0.1400%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / Total Inv. Base) + Federal Income Tax) * State Income Tax Rate) / (1 - State Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Line 8, Col. (1); Connecticut Corporate Tax Rate

9 = ((0.26% + ((0 + 0) / 85,230,067) + 0.1400%) * 9.00%)
10 (1 - 9.00%) Connecticut Corporate Tax Rate

11 = 0.0396%

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.4396%

13 INVESTMENT BASE 85,230,067 Line 16, Col. (4)

14 x Cost of Capital Rate 0.4396% Line 12, Col. (1)

15 = Investment Return and Income Taxes $ 374,671 to Sheet 4a, Line 14(4)

Note 1: CAP on ROE incentives per FERC Order in Docket No. EL11-66 dated March 3, 2015.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.

Notes:

(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-224, Schedule 1, Page 3 of 4, Line 18
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Bethel-Norwalk
Sheet 8

Line No.	(A)	(B) Year End		(C) Localized Trans. Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Depreciation Expense							
1	Transmission Depreciation					2,894,776	Sheet 9, Line 58	(a)
2	General Depreciation	4,980,574	Note 4				FF1 page 336 ln. 10, footnote	(a)
3	*less:* Convex-related General Plant Depreciation Expense	1,110,693					Note 1	(a)
4	Subtotal: General Plant Depr Exp, net of Convex (line 2-3)	3,869,881		4.0407%	Note 2	156,370		(a)
5	Total (line 1+4)					3,051,146		(a)
6	Amortization of Loss on Reacquired Debt	1,309,927		1.4915%	Note 3	19,538	FF1 page 117 ln. 64	(a)
7	Amortization of Investment Tax Credits	1,511,975		1.4915%	Note 3	22,551	FF1 page 266 ln. 8 (f)	(a)
8	Property Taxes	120,836,131		1.4915%	Note 3	1,802,271	FF1 page 263 ln. 24i & 25i	(a)
	Payroll Tax Expense							
9	Federal Unemployment	5,226					FF1 page 262 ln. 3i, footnote	(a)
10	FICA	233,351					FF1 page 262 ln. 5i, footnote	(a)
11	Medicare	65,613					FF1 page 262 ln. 9i, footnote	(a)
12	CT Unemployment	16,786					FF1 page 262 ln. 15i, footnote	(a)
13	MA Unemployment	(285)					FF1 page 262 ln. 32i, footnote	(a)
14	MA Universal Health	64					FF1 page 262 ln. 33i, footnote	(a)
15	NH Unemployment	1,754					FF1 page 262.1 ln. 4i, footnote	(a)
16	NJ Unemployment	-					FF1 page 262 footnote	(a)
17	DC Unemployment	11					FF1 page 262.1 ln. 14i, footnote	(a)
18	FL Unemployment	1					FF1 page 262.1 ln. 18i, footnote	(a)
19	MI Unemployment	6					FF1 page 262.1 ln. 22i, footnote	(a)
20	NY Unemployment	-					FF1 page 262.1 ln. 10i, footnote	(a)
21	Total (Line 9 to 20)	322,527	Note 4	4.0407%	Note 2	13,032		
	Transmission Operation and Maintenance							
22	Operation and Maintenance	77,432,007					FF1 page 321 ln. 112	(a)
23	Transmission of Electricity by Others - #565	21,727,966					FF1 page 321 ln. 96	(a)
24	Load Dispatching - #561	-					FF1 page 321 ln. 84	(a)
25	Account 561.1	3,245,594					FF1 page 321 ln. 85	(a)
26	Account 561.2	5,212,556					FF1 page 321 ln. 86	(a)
27	Account 561.3	2,238,612					FF1 page 321 ln. 87	(a)
28	Account 561.4	7,157,291					FF1 page 321 ln. 88	(a)
29	O&M (line 22 - lines 23 to 28)	37,849,988		4.0407%	Note 2	1,529,404		(a)
	Transmission-related Administrative and General							
30	Administrative and General	37,202,294	Note 4				FF1 page 320 ln. 197 b, footnote	(a)
31	less: Property Insurance (#924)	763,857	Note 4				FF1 Page 320 ln. 185 b, footnote	(a)
32	less: Regulatory Commission Expenses (#928)	2,749,411	Note 4				FF1 page 320 ln. 189 b, footnote	(a)
33	less: General Advertising Expense (#930.1)	10,766	Note 4				FF1 page 320 ln. 191 b, footnote	(a)
34	Subtotal (line 30 - lines 31 to 33)	33,678,260		4.0407%	Note 2	1,360,837		(a)
35	plus: Property Insurance	1,413,419		1.4915%	Note 3	21,081	FF1 page 323 ln. 185	(a)
36	plus: Trans. Regulatory Comm. Exp.	2,749,411		4.0407%	Note 2	111,095	FF1 page 320 ln. 189 b, footnote	(a)
37	plus: Trans. Related General Advertising Expense	10,766		4.0407%	Note 2	435	FF1 page 320 ln. 191 b, footnote	(a)
38	plus: Trans. Related Public Education Expense	-				-	FF1 page 114 ln. 49, footnote	(a)
39	plus: Trans. Merger-Related Costs	7,153,326		4.0407%		289,044	Exhibit No. ES-220, Page 1 of 8, Line 2(C)	(b)
40	Total A&G (sum of lines 34 to 38)	45,005,182				1,782,492		(b)
41	Transmission Related Taxes and Fees	9,854,673		4.0407%	Note 2	398,198	Note 5	(a)

Note 1: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.
Note 5: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment B.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Middletown-Norwalk
Sheet 1a

Line No.	(A)	Attachment I Reference Section:	(B)	(C) Source	(D) Notes
	I. INVESTMENT BASE				
1	Transmission Plant	II(A)(1)(a)	62,028,638	Sheet 2, Line 5	(a)
2	Transmission Plant Held for Future Use	II(A)(1)(b)	-	Sheet 2, Line 6	(a)
3	Accumulated Depreciation	II(A)(1)(c)	9,382,562	Sheet 2, Line 11	(a)
4	Accumulated Deferred Income Taxes	II(A)(1)(d)	7,626,580	Sheet 2, Line 12	(a)
5	Loss On Reacquired Debt	II(A)(1)(e)	93,059	Sheet 2, Line 13	(a)
6	Other Regulatory Assets	II(A)(1)(f)	214,707	Sheet 2, Line 14	(b)
7	Net Investment (Line 1+2-3-4+5)		45,327,262		(b)
8	Prepayments	II(A)(1)(g)	389,937	Sheet 2, Line 15	(a)
9	Materials & Supplies	II(A)(1)(h)	722,824	Sheet 2, Line 16	(a)
10	Cash Working Capital	II(A)(1)(i)	205,011	Sheet 2, Line 23	(b)
11	Total Investment Base (Line 6+7+8+9)		46,645,034		(b)
	II. REVENUE REQUIREMENTS				
12	Investment Return and Income Taxes	II(A)	6,021,446	Sheet 4a, Line 15(4)	(b)
13	Depreciation Expense	II(B)	1,584,643	Sheet 8, Line 5	(a)
14	Amortization of Loss on Reacquired Debt	II(C)	9,675	Sheet 8, Line 6	(a)
15	Investment Tax Credit	II(D)	(11,167)	Sheet 8, Line 7	(a)
16	Property Tax Expense	II(E)	892,496	Sheet 8, Line 8	(a)
17	Payroll Tax Expense	II(F)	6,454	Sheet 8, Line 21	(a)
18	Operation & Maintenance Expense	II(G)	757,378	Sheet 8, Line 29	(a)
19	Administrative & General Expense	II(H)	882,711	Sheet 8, Line 40	(b)
20	Support Expenses	II(I)	-		(a)
21	Transmission Related Taxes and Fees	II(J)	197,192	Sheet 8, Line 41	(a)
22	Total Revenue Requirements (Line 11 thru 20)		10,340,828		(b)

Note:
Investment Return and Income Taxes (line 11 above) was calculated based on the Total Investment Base at 11.07% ROE, plus the Localized Post-2003 PTF Transmission Base (lines 1-3-4) at the .67% capped Incremental ROE.

Notes:

(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247

(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Middletown-Norwalk
Sheet 2

Line No.	(A)	(B) Trans. Related Average		(C) Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Transmission Plant							
1	Localized Transmission Plant					60,288,933	Sheet 3, Line 18	(a)
2	Transmission General Plant	102,812,641	Note 4				FF1 page 204 ln. 96, footnote	(a)
3	Less: Convex-related General Plant	15,870,872					Note 1	(a)
4	Subtotal: General Plant, net of Convex (line 2 - 3)	86,941,769		2.0010%	Note 2	1,739,705		(a)
5	Total (line 1+4)					62,028,638		(a)
6	Localized Transmission Plant Held for Future Use					-		(a)
	Transmission Accumulated Depreciation							
7	Localized Transmission Accum. Depreciation					8,934,977	Sheet 9, Line 84(I)	(a)
8	General Plant Accum. Depreciation	26,085,325	Note 4				FF1 page 219 ln. 28, footnote	(a)
9	Less: Convex-related General Plant Acc Depr	3,717,252					Note 1	(a)
10	Subtotal: General Plant A/D, net of Convex (line 8-9)	22,368,074		2.0010%	Note 2	447,585		(a)
11	Total (line 7+10)					9,382,562		(a)
12	Transmission Accumulated Deferred Taxes					7,626,580	Sheet 10, Line 105	(a)
13	Unam. Loss on Reacquired Debt (189)	12,599,425		0.7386%	Note 3	93,059	FF1 page 111 ln. 81	(a)
14	Localized Transmission Other Regulatory Assets	10,729,989		2.0010%		214,707	Exhibit No. ES-220, Page 1 of 8, Line 4(C)	(b)
15	Transmission Prepayments (165)	19,487,085	Note 4	2.0010%	Note 2	389,937	FF1 page 110 ln. 57, footnote	(a)
16	Transmission Materials and Supplies	36,123,136		2.0010%	Note 2	722,824	FF1 page 227 ln. 8	(a)
	Cash Working Capital							
17	Localized Operation & Maintenance Expense					757,378	Sheet 8, Line 29	(a)
18	Localized Administrative & General Expense					882,711	Sheet 8, Line 40	(c)
19	Subtotal (line 16+17)					1,640,089		(c)
20	12.5% allowance					0.125	x 45 / 360	(a)
21	Total current Year End (line 18*19)					205,011		(c)
22	Prior Year End Cash Working Capital					205,011		(d)
23	Average Cash Working Capital [(line 20+21)/2]					205,011		(c)

Note 1: Reflects actual information per Eversource's accounting records.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset
(c) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses
(d) Exhibit No. 226, Schedule 3, Page 8 of 26, Line 21(D)

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Middletown-Norwalk
Sheet 4a

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559	Note 2	46.27%	5.36%	Note 2	2.48%		
2	PREFERRED STOCK	$ 116,842,775		2.14%	4.80%		0.10%	0.10%	
3	COMMON EQUITY	$ 2,820,159,065		51.59%	11.07%	Note 1	5.71%	5.71%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399		100.00%			8.29%	5.81%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 8.29% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate) / Total Inv. Base)) * Federal Income Tax Rate)

Source: Line 4, Col. (5); Sheet 8, Line 7; Sheet 6, Line 1; Sheet 1, Line 10; Federal Corporate Tax Rate

6 = ((5.81% + (((11,167) + 46,171) /
7 (1 - 35.00%) 46,645,034)) * 35.00%)

Federal Corporate Tax Rate

8 = 3.1689%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate) / Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)

Source: Line 4, Col. (5); Sheet 8, Line 7; Sheet 6, Line 1; Sheet 1, Line 10; Line 8, Col. (1); Connecticut Corporate Tax Rate

9 = ((5.81% + (((11,167) + 46,171) / 46,645,034) + 3.1689%) * 9.00%)
10 (1 - 9.00%)

Connecticut Corporate Tax Rate

11 = 0.8954%

12 (a)+(b)+(c) **Cost of Capital Rate** = 12.3543%

13	INVESTMENT BASE	46,645,034	Sheet 1, Line 10
14			
15	x Cost of Capital Rate	12.3543%	Line 12, Col. (1)
16	= Investment Return and Income Taxes	$ 5,762,667	

Total Investment Return and Income Taxes		
@11.07%	$ 5,762,667	Line 16, Col. (1)
@.67%	$ 258,779	Sheet 5a, Line 17
	$ 6,021,446	To Sheet 1a, Line 11

Note 1: ROE per FERC Order in Docket No. ER11-66 dated October 16, 2014.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes:

(1) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Middletown-Norwalk
Sheet 5a

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559	Note 2	46.27%					
2	PREFERRED STOCK	$ 116,842,775		2.14%					
3	COMMON EQUITY	$ 2,820,159,065		51.59%	0.50%	Note 1	0.26%	0.26%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399		100.00%			0.26%	0.26%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.26% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate) / Total Inv. Base)) * Federal Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Federal Corporate Tax Rate

6 = ((0.26% + ((0 + 0) / 46,645,034)) * 35.00%)

7 (1 - 35.00%) (Federal Corporate Tax Rate)

8 = 0.1400%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate) / Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Line 8, Col. (1); Connecticut Corporate Tax Rate

9 = ((0.26% + ((0 + 0) / 46,645,034) + 0.1400%) * 9.00%)

10 (1 - 9.00%) (Connecticut Corporate Tax Rate)

11 = 0.0396%

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.4396%

13 INVESTMENT BASE 46,645,034 Line 16, Col. (4)

14 x Cost of Capital Rate 0.4396% Line 12, Col. (1)

15 = Investment Return and Income Taxes $ 205,052 to Sheet 4a, Line 14(4)

Note 1: CAP on ROE incentives per FERC Order in Docket No. EL11-66 dated March 3, 2015.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.

Notes:

(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-224, Schedule 1, Page 3 of 4, Line 18
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Middletown-Norwalk
Sheet 8

Line No.	(A)	(B) Year End		(C) Localized Trans. Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Depreciation Expense							
1	Transmission Depreciation					1,507,207	Sheet 9, Line 86	(a)
2	General Depreciation	4,980,574	Note 4				FF1 page 336 ln. 10, footnote	(a)
3	*less:* Convex-related General Plant Depreciation Expense	1,110,693					Note 1	(a)
4	Subtotal: General Plant Depr Exp, net of Convex (line 2-3)	3,869,881		2.0010%	Note 2	77,436		(a)
5	Total (line 1+4)					1,584,643		(a)
6	Amortization of Loss on Reacquired Debt	1,309,927		0.7386%	Note 3	9,675	FF1 page 117 ln. 64	(a)
7	Amortization of Investment Tax Credits	1,511,975		0.7386%	Note 3	11,167	FF1 page 266 ln. 8 (f)	(a)
8	Property Taxes	120,836,131		0.7386%	Note 3	892,496	FF1 page 263 ln. 24i & 25i	(a)
	Payroll Tax Expense							
9	Federal Unemployment	5,226					FF1 page 262 ln. 3i, footnote	(a)
10	FICA	233,351					FF1 page 262 ln. 5i, footnote	(a)
11	Medicare	65,613					FF1 page 262 ln. 9i, footnote	(a)
12	CT Unemployment	16,786					FF1 page 262 ln. 15i, footnote	(a)
13	MA Unemployment	(285)					FF1 page 262 ln. 32i, footnote	(a)
14	MA Universal Health	64					FF1 page 262 ln. 33i, footnote	(a)
15	NH Unemployment	1,754					FF1 page 262.1 ln. 4i, footnote	(a)
16	NJ Unemployment	-					FF1 page 262 footnote	(a)
17	DC Unemployment	11					FF1 page 262.1 ln. 14i, footnote	(a)
18	FL Unemployment	1					FF1 page 262.1 ln. 18i, footnote	(a)
19	MI Unemployment	6					FF1 page 262.1 ln. 22i, footnote	(a)
20	NY Unemployment	-					FF1 page 262.1 ln. 10i, footnote	(a)
21	Total (Line 9 to 20)	322,527	Note 4	2.0010%	Note 2	6,454		
	Transmission Operation and Maintenance							
22	Operation and Maintenance	77,432,007					FF1 page 321 ln. 112	(a)
23	Transmission of Electricity by Others - #565	21,727,966					FF1 page 321 ln. 96	(a)
24	Load Dispatching - #561	-					FF1 page 321 ln. 84	(a)
25	Account 561.1	3,245,594					FF1 page 321 ln. 85	(a)
26	Account 561.2	5,212,556					FF1 page 321 ln. 86	(a)
27	Account 561.3	2,238,612					FF1 page 321 ln. 87	(a)
28	Account 561.4	7,157,291					FF1 page 321 ln. 88	(a)
29	O&M (line 22 - lines 23 to 28)	37,849,988		2.0010%	Note 2	757,378		(a)
	Transmission-related Administrative and General							
30	Administrative and General	37,202,294	Note 4				FF1 page 320 ln. 197 b, footnote	(a)
31	less: Property Insurance (#924)	763,857	Note 4				FF1 Page 320 ln. 185 b, footnote	(a)
32	less: Regulatory Commission Expenses (#928)	2,749,411	Note 4				FF1 page 320 ln. 189 b, footnote	(a)
33	less: General Advertising Expense (#930.1)	10,766	Note 4				FF1 page 320 ln. 191 b, footnote	(a)
34	Subtotal (line 30 - lines 31 to 33)	33,678,260		2.0010%	Note 2	673,902		(a)
35	plus: Property Insurance	1,413,419		0.7386%	Note 3	10,440	FF1 page 323 ln. 185	(a)
36	plus: Trans. Regulatory Comm. Exp.	2,749,411		2.0010%	Note 2	55,016	FF1 page 320 ln. 189 b, footnote	(a)
37	plus: Trans. Related General Advertising Expense	10,766		2.0010%	Note 2	215	FF1 page 320 ln. 191 b, footnote	(a)
38	plus: Trans. Related Public Education Expense	-				-	FF1 page 114 ln. 49, footnote	(a)
39	plus: Trans. Merger-Related Costs	7,153,326		2.0010%		143,138	Exhibit No. ES-220, Page 1 of 8, Line 2(C)	(b)
40	Total A&G (sum of lines 34 to 38)	45,005,182				882,711		(b)
41	Transmission Related Taxes and Fees	9,854,673		2.0010%	Note 2	197,192	Note 5	(a)

Note 1: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.
Note 5: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment B.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Glenbrook Cables
Sheet 1a

Line No.	(A)	Attachment I Reference Section:	(B)	(C) Source	(D) Notes
	I. INVESTMENT BASE				
1	Transmission Plant	II(A)(1)(a)	2,644,161	Sheet 2, Line 5	(a)
2	Transmission Plant Held for Future Use	II(A)(1)(b)	31,396,972	Sheet 2, Line 6	(a)
3	Accumulated Depreciation	II(A)(1)(c)	353,497	Sheet 2, Line 11	(a)
4	Accumulated Deferred Income Taxes	II(A)(1)(d)	323,209	Sheet 2, Line 12	(a)
5	Loss On Reacquired Debt	II(A)(1)(e)	3,969	Sheet 2, Line 13	(a)
6	Other Regulatory Assets	II(A)(1)(f)	9,153	Sheet 2, Line 14	(b)
7	Net Investment (Line 1+2-3-4+5)		33,377,549		(b)
8	Prepayments	II(A)(1)(g)	16,622	Sheet 2, Line 15	(a)
9	Materials & Supplies	II(A)(1)(h)	30,813	Sheet 2, Line 16	(a)
10	Cash Working Capital	II(A)(1)(i)	8,739	Sheet 2, Line 23	(b)
11	Total Investment Base (Line 6+7+8+9)		33,433,723		(b)
	II. REVENUE REQUIREMENTS				
12	Investment Return and Income Taxes	II(A)	4,125,537	Sheet 4a, Line 15(4)	(b)
13	Depreciation Expense	II(B)	63,152	Sheet 8, Line 5	(a)
14	Amortization of Loss on Reacquired Debt	II(C)	413	Sheet 8, Line 6	(a)
15	Investment Tax Credit	II(D)	(476)	Sheet 8, Line 7	(a)
16	Property Tax Expense	II(E)	38,063	Sheet 8, Line 8	(a)
17	Payroll Tax Expense	II(F)	275	Sheet 8, Line 21	(a)
18	Operation & Maintenance Expense	II(G)	32,286	Sheet 8, Line 29	(a)
19	Administrative & General Expense	II(H)	37,629	Sheet 8, Line 40	(b)
20	Support Expenses	II(I)	-		(a)
21	Transmission Related Taxes and Fees	II(J)	8,406	Sheet 8, Line 41	(a)
22	Total Revenue Requirements (Line 11 thru 20)		4,305,285		(b)

Note:
Investment Return and Income Taxes (line 11 above) was calculated based on the Total Investment Base at 11.07% ROE, plus the Localized Post-2003 PTF Transmission Base (lines 1-3-4) at the .67% capped Incremental ROE.

Notes:

(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247

(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Glenbrook Cables
Sheet 2

Line No.	(A)	(B) Trans. Related Average		(C) Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Transmission Plant							
1	Localized Transmission Plant					2,570,000	Sheet 3, Line 17	(a)
2	Transmission General Plant	102,812,641	Note 4				FF1 page 204 ln. 96, footnote	(a)
3	Less: Convex-related General Plant	15,870,872					Note 1	(a)
4	Subtotal: General Plant, net of Convex (line 2 - 3)	86,941,769		0.0853%	Note 2	74,161		(a)
5	Total (line 1+4)					2,644,161		(a)
6	Localized Transmission Plant Held for Future Use					31,396,972		(a)
	Transmission Accumulated Depreciation							
7	Localized Transmission Accum. Depreciation					334,418	Sheet 9, Line 17(I)	(a)
8	General Plant Accum. Depreciation	26,085,325	Note 4				FF1 page 219 ln. 28, footnote	(a)
9	Less: Convex-related General Plant Acc Depr	3,717,252					Note 1	(a)
10	Subtotal: General Plant A/D, net of Convex (line 8-9)	22,368,074		0.0853%	Note 2	19,080		(a)
11	Total (line 7+10)					353,497		(a)
12	Transmission Accumulated Deferred Taxes					323,209	Sheet 10, Line 32	(a)
13	Unam. Loss on Reacquired Debt (189)	12,599,425		0.0315%	Note 3	3,969	FF1 page 111 ln. 81	(a)
14	Localized Transmission Other Regulatory Assets	10,729,989		0.0853%		9,153	Exhibit No. ES-220, Page 1 of 8, Line 4(C)	(b)
15	Transmission Prepayments (165)	19,487,085	Note 4	0.0853%	Note 2	16,622	FF1 page 110 ln. 57, footnote	(a)
16	Transmission Materials and Supplies	36,123,136		0.0853%	Note 2	30,813	FF1 page 227 ln. 8	(a)
	Cash Working Capital							
17	Localized Operation & Maintenance Expense					32,286	Sheet 8, Line 29	(a)
18	Localized Administrative & General Expense					37,629	Sheet 8, Line 40	(c)
19	Subtotal (line 16+17)					69,915		(c)
20	12.5% allowance					0.125	x 45 / 360	(a)
21	Total current Year End (line 18*19)					8,739		(c)
22	Prior Year End Cash Working Capital					8,739		(d)
23	Average Cash Working Capital [(line 20+21)/2]					8,739		(c)

Note 1: Reflects actual information per Eversource's accounting records.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset
(c) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses
(d) Exhibit No. 226, Schedule 3, Page 13 of 26, Line 21(D)

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Glenbrook Cables
Sheet 4a

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559	Note 2	46.27%	5.36%	Note 2	2.48%		
2	PREFERRED STOCK	$ 116,842,775		2.14%	4.80%		0.10%	0.10%	
3	COMMON EQUITY	$ 2,820,159,065		51.59%	11.07%	Note 1	5.71%	5.71%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399		100.00%			8.29%	5.81%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 8.29% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / Total Inv. Base)) * Federal Income Tax Rate)
(1 - Federal Income Tax Rate)

Line		R.O.E.		Total Inv. (Tax Credit)		Eq. AFUDC of Deprec. Exp.		Total Inv. Base		Federal Income Tax Rate	
	Source:	Line 4, Col. (5)		Sheet 8, Line 7		Sheet 6, Line 1		Sheet 1, Line 10		Federal Corporate Tax Rate	
6	= ((	5.81%	+ ((	(476)	+	1,968	) /	33,433,723	)) *	35.00%	)
7			(	1	-	35.00% Federal Corporate Tax Rate	)				
8	=	3.1309%									

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)
(1 - State Income Tax Rate)

Line		R.O.E.		Total Inv. (Tax Credit)		Eq. AFUDC of Deprec. Exp.		Total Inv. Base		Federal Income Tax		State Income Tax Rate	
	Source:	Line 4, Col. (5)		Sheet 8, Line 7		Sheet 6, Line 1		Sheet 1, Line 10		Line 8, Col. (1)		Connecticut Corporate Tax Rate	
9	= ((	5.81%	+ ((	(476)	+	1,968	) /	33,433,723	) +	3.1309%	) *	9.00%	)
10			(	1	-	9.00% Connecticut Corporate Tax Rate	)						
11	=	0.8847%											

12 (a)+(b)+(c) **Cost of Capital Rate** = 12.3056%

Line			
13	INVESTMENT BASE	33,433,723	Sheet 1, Line 10
14			
15	x Cost of Capital Rate	12.3056%	Line 12, Col. (1)
16	= Investment Return and Income Taxes	$ 4,114,220	

Total Investment Return and Income Taxes			
@11.07%	$	4,114,220	Line 16, Col. (1)
@.67%	$	11,317	Sheet 5a, Line 17
	$	4,125,537	To Sheet 1a, Line 11

Note 1: ROE per FERC Order in Docket No. ER11-66 dated October 16, 2014.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes:

(1) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Glenbrook Cables

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559	Note 2	46.27%					
2	PREFERRED STOCK	$ 116,842,775		2.14%					
3	COMMON EQUITY	$ 2,820,159,065		51.59%	0.50%	Note 1	0.26%	0.26%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399		100.00%			0.26%	0.26%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.26% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate) / Total Inv. Base)) * Federal Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Federal Corporate Tax Rate

6 = ((0.26% + ((0 + 0) / Federal Corporate Tax Rate 33,433,723)) * 35.00%)
7 (1 - 35.00%)
Federal Corporate Tax Rate

8 = 0.1400%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate) / Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Line 8, Col. (1); Connecticut Corporate Tax Rate

9 = ((0.26% + ((0 + 0) / 33,433,723) + 0.1400%) * 9.00%)
10 (1 - 9.00%)
Connecticut Corporate Tax Rate

11 = 0.0396%

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.4396%

13 INVESTMENT BASE 33,433,723 Line 16, Col. (4)

14 x Cost of Capital Rate 0.4396% Line 12, Col. (1)

15 = Investment Return and Income Taxes $ 146,975 to Sheet 4a, Line 14(4)

Note 1: CAP on ROE incentives per FERC Order in Docket No. EL11-66 dated March 3, 2015.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.

Notes:

(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-224, Schedule 1, Page 3 of 4, Line 18

(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Glenbrook Cables
Sheet 8

Line No.	(A)	(B) Year End		(C) Localized Trans. Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Depreciation Expense							
1	Transmission Depreciation					59,851	Sheet 9, Line 19	(a)
2	General Depreciation	4,980,574	Note 4				FF1 page 336 ln. 10, footnote	(a)
3	*less:* Convex-related General Plant Depreciation Expense	1,110,693					Note 1	(a)
4	Subtotal: General Plant Depr Exp, net of Convex (line 2-3)	3,869,881		0.0853%	Note 2	3,301		(a)
5	Total (line 1+4)					63,152		(a)
6	Amortization of Loss on Reacquired Debt	1,309,927		0.0315%	Note 3	413	FF1 page 117 ln. 64	(a)
7	Amortization of Investment Tax Credits	1,511,975		0.0315%	Note 3	476	FF1 page 266 ln. 8 (f)	(a)
8	Property Taxes	120,836,131		0.0315%	Note 3	38,063	FF1 page 263 ln. 24i & 25i	(a)
	Payroll Tax Expense							
9	Federal Unemployment	5,226					FF1 page 262 ln. 3i, footnote	(a)
10	FICA	233,351					FF1 page 262 ln. 5i, footnote	(a)
11	Medicare	65,613					FF1 page 262 ln. 9i, footnote	(a)
12	CT Unemployment	16,786					FF1 page 262 ln. 15i, footnote	(a)
13	MA Unemployment	(285)					FF1 page 262 ln. 32i, footnote	(a)
14	MA Universal Health	64					FF1 page 262 ln. 33i, footnote	(a)
15	NH Unemployment	1,754					FF1 page 262.1 ln. 4i, footnote	(a)
16	NJ Unemployment	-					FF1 page 262 footnote	(a)
17	DC Unemployment	11					FF1 page 262.1 ln. 14i, footnote	(a)
18	FL Unemployment	1					FF1 page 262.1 ln. 18i, footnote	(a)
19	MI Unemployment	6					FF1 page 262.1 ln. 22i, footnote	(a)
20	NY Unemployment	-					FF1 page 262.1 ln. 10i, footnote	(a)
21	Total (Line 9 to 20)	322,527	Note 4	0.0853%	Note 2	275		
	Transmission Operation and Maintenance							
22	Operation and Maintenance	77,432,007					FF1 page 321 ln. 112	(a)
23	Transmission of Electricity by Others - #565	21,727,966					FF1 page 321 ln. 96	(a)
24	Load Dispatching - #561	-					FF1 page 321 ln. 84	(a)
25	Account 561.1	3,245,594					FF1 page 321 ln. 85	(a)
26	Account 561.2	5,212,556					FF1 page 321 ln. 86	(a)
27	Account 561.3	2,238,612					FF1 page 321 ln. 87	(a)
28	Account 561.4	7,157,291					FF1 page 321 ln. 88	(a)
29	O&M (line 22 - lines 23 to 28)	37,849,988		0.0853%	Note 2	32,286		(a)
	Transmission-related Administrative and General							
30	Administrative and General	37,202,294	Note 4				FF1 page 320 ln. 197 b, footnote	(a)
31	**less:** Property Insurance (#924)	763,857	Note 4				FF1 Page 320 ln. 185 b, footnote	(a)
32	**less:** Regulatory Commission Expenses (#928)	2,749,411	Note 4				FF1 page 320 ln. 189 b, footnote	(a)
33	**less:** General Advertising Expense (#930.1)	10,766	Note 4				FF1 page 320 ln. 191 b, footnote	(a)
34	Subtotal (line 30 - lines 31 to 33)	33,678,260		0.0853%	Note 2	28,728		(a)
35	**plus:** Property Insurance	1,413,419		0.0315%	Note 3	445	FF1 page 323 ln. 185	(a)
36	**plus:** Trans. Regulatory Comm. Exp.	2,749,411		0.0853%	Note 2	2,345	FF1 page 320 ln. 189 b, footnote	(a)
37	**plus:** Trans. Related General Advertising Expense	10,766		0.0853%	Note 2	9	FF1 page 320 ln. 191 b, footnote	(a)
38	**plus:** Trans. Related Public Education Expense	-				-	FF1 page 114 ln. 49, footnote	(a)
39	**plus:** Trans. Merger-Related Costs	7,153,326		0.0853%		6,102	Exhibit No. ES-220, Page 1 of 8, Line 2(C)	(b)
40	Total A&G (sum of lines 34 to 38)	45,005,182				37,629		(b)
41	Transmission Related Taxes and Fees	9,854,673		0.0853%	Note 2	8,406	Note 5	(a)

Note 1: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.
Note 5: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment B.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 1a

Line No.	(A)	Attachment I Reference Section:	(B)	(C) Source	(D) Notes
	I. INVESTMENT BASE				
1	Transmission Plant	II(A)(1)(a)	3,169,795	Sheet 2, Line 5	(a)
2	Transmission Plant Held for Future Use	II(A)(1)(b)	-	Sheet 2, Line 6	(a)
3	Accumulated Depreciation	II(A)(1)(c)	116,694	Sheet 2, Line 11	(a)
4	Accumulated Deferred Income Taxes	II(A)(1)(d)	265,445	Sheet 2, Line 12	(a)
5	Loss On Reacquired Debt	II(A)(1)(e)	4,750	Sheet 2, Line 13	(a)
6	Other Regulatory Assets	II(A)(1)(f)	10,977	Sheet 2, Line 14	(b)
7	Net Investment (Line 1+2-3-4+5)		2,803,383		(b)
8	Prepayments	II(A)(1)(g)	19,935	Sheet 2, Line 15	(a)
9	Materials & Supplies	II(A)(1)(h)	36,954	Sheet 2, Line 16	(a)
10	Cash Working Capital	II(A)(1)(i)	10,481	Sheet 2, Line 23	(b)
11	Total Investment Base (Line 6+7+8+9)		2,870,753		(b)
	II. REVENUE REQUIREMENTS				
12	Investment Return and Income Taxes	II(A)	370,515	Sheet 4a, Line 15(4)	(b)
13	Depreciation Expense	II(B)	78,802	Sheet 8, Line 5	(a)
14	Amortization of Loss on Reacquired Debt	II(C)	494	Sheet 8, Line 6	(a)
15	Investment Tax Credit	II(D)	(570)	Sheet 8, Line 7	(a)
16	Property Tax Expense	II(E)	45,555	Sheet 8, Line 8	(a)
17	Payroll Tax Expense	II(F)	330	Sheet 8, Line 21	(a)
18	Operation & Maintenance Expense	II(G)	38,721	Sheet 8, Line 29	(a)
19	Administrative & General Expense	II(H)	45,128	Sheet 8, Line 40	(b)
20	Support Expenses	II(I)	-		(a)
21	Transmission Related Taxes and Fees	II(J)	10,081	Sheet 8, Line 41	(a)
22	Total Revenue Requirements (Line 11 thru 20)		589,056		(b)

Note:
Investment Return and Income Taxes (line 11 above) was calculated based on the Total Investment Base at 11.07% ROE, plus the Localized PTF Transmission Base (lines 1-3-4) at the .67% capped Incremental ROE.

Notes:

(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247

(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 2

Line No.	(A)	(B) Trans. Related Average		(C) Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Transmission Plant							
1	Localized Transmission Plant					3,080,854	Sheet 3, Line 18	(a)
2	Transmission General Plant	102,812,641	Note 4				FF1 page 204 ln. 96, footnote	(a)
3	Less: Convex-related General Plant	15,870,872					Note 1	(a)
4	Subtotal: General Plant, net of Convex (line 2 - 3)	86,941,769		0.1023%	Note 2	88,941		(a)
5	Total (line 1+4)					3,169,795		(a)
6	Localized Transmission Plant Held for Future Use					-		(a)
	Transmission Accumulated Depreciation							
7	Localized Transmission Accum. Depreciation					93,811	Sheet 9, Line 10(I)	(a)
8	General Plant Accum. Depreciation	26,085,325	Note 4				FF1 page 219 ln. 28, footnote	(a)
9	Less: Convex-related General Plant Acc Depr	3,717,252					Note 1	(a)
10	Subtotal: General Plant A/D, net of Convex (line 8-9)	22,368,074		0.1023%	Note 2	22,883		(a)
11	Total (line 7+10)					116,694		(a)
12	Transmission Accumulated Deferred Taxes					265,445	Sheet 10, Line 46	(a)
13	Unam. Loss on Reacquired Debt (189)	12,599,425		0.0377%	Note 3	4,750	FF1 page 111 ln. 81	(a)
14	Localized Transmission Other Regulatory Assets	10,729,989		0.1023%		10,977	Exhibit No. ES-220, Page 1 of 8, Line 4(C)	(b)
15	Transmission Prepayments (165)	19,487,085	Note 4	0.1023%	Note 2	19,935	FF1 page 110 ln. 57, footnote	(a)
16	Transmission Materials and Supplies	36,123,136		0.1023%	Note 2	36,954	FF1 page 227 ln. 8	(a)
	Cash Working Capital							
17	Localized Operation & Maintenance Expense					38,721	Sheet 8, Line 29	(a)
18	Localized Administrative & General Expense					45,128	Sheet 8, Line 40	(c)
19	Subtotal (line 16+17)					83,849		(c)
20	12.5% allowance					0.125	x 45 / 360	(a)
21	Total current Year End (line 18*19)					10,481		(c)
22	Prior Year End Cash Working Capital					10,481		(d)
23	Average Cash Working Capital [(line 20+21)/2]					10,481		(c)

Note 1: Reflects actual information per Eversource's accounting records.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset
(c) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses
(d) Exhibit No. 226, Schedule 3, Page 18 of 26, Line 21(D)

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 4a

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559	Note 2	46.27%	5.36%	Note 2	2.48%		
2	PREFERRED STOCK	$ 116,842,775		2.14%	4.80%		0.10%	0.10%	
3	COMMON EQUITY	$ 2,820,159,065		51.59%	11.07%	Note 1	5.71%	5.71%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399		100.00%			8.29%	5.81%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 8.29% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate)) / Total Inv. Base)) * Federal Income Tax Rate)

Line		Line 4, Col. (5)		Sheet 8, Line 7		Sheet 6, Line 1		Sheet 1, Line 10		Federal Corporate Tax Rate	
	Source:	Line 4, Col. (5)		Sheet 8, Line 7		Sheet 6, Line 1		Sheet 1, Line 10		Federal Corporate Tax Rate	
6	= ((	5.81%	+ ((	(570)	+	2,360	) /	2,870,753	)) *	35.00%	)
7			(	1	-	35.00% Federal Corporate Tax Rate	)				
8	=	3.1620%									

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate)) / Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)

Line												
	Source:	Line 4, Col. (5)		Sheet 8, Line 7		Sheet 6, Line 1		Sheet 1, Line 10		Line 8, Col. (1)		Connecticut Corporate Tax Rate
9	= ((	5.81%	+ ((	(570)	+	2,360	) /	2,870,753	) +	3.1620%	) *	9.00%)
10			(	1	-	9.00% Connecticut Corporate Tax Rate	)					
11	=	0.8935%										

12 (a)+(b)+(c) **Cost of Capital Rate** = 12.3455%

Line			
13	INVESTMENT BASE	2,870,753	Sheet 1, Line 10
14			
15	x Cost of Capital Rate	12.3455%	Line 12, Col. (1)
16	= Investment Return and Income Taxes	$ 354,409	

Total Investment Return and Income Taxes

@11.07%	$ 354,409	Line 16, Col. (1)
@.67%	$ 16,106	Sheet 5a, Line 17
	$ 370,515	To Sheet 1a, Line 11

Note 1: ROE per FERC Order in Docket No. ER11-66 dated October 16, 2014.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes:

(1) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 5a

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559	Note 2	46.27%					
2	PREFERRED STOCK	$ 116,842,775		2.14%					
3	COMMON EQUITY	$ 2,820,159,065		51.59%	0.50%	Note 1	0.26%	0.26%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399		100.00%			0.26%	0.26%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.26% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / Total Inv. Base)) * Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Federal Corporate Tax Rate

6 = ((0.26% + ((0 + 0) / 2,870,753)) * 35.00%)
7 / (1 - 35.00%) Federal Corporate Tax Rate

8 = 0.1400%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / Total Inv. Base) + Federal Income Tax) * State Income Tax Rate) / (1 - State Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Line 8, Col. (1); Connecticut Corporate Tax Rate

9 = ((0.26% + ((0 + 0) / 2,870,753) + 0.1400%) * 9.00%)
10 / (1 - 9.00%) Connecticut Corporate Tax Rate

11 = 0.0396%

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.4396%

13	INVESTMENT BASE	2,870,753	Line 16, Col. (4)
14	x Cost of Capital Rate	0.4396%	Line 12, Col. (1)
15	= Investment Return and Income Taxes	$ 12,620	to Sheet 4a, Line 14(4)

Note 1: CAP on ROE incentives per FERC Order in Docket No. EL11-66 dated March 3, 2015.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.

Notes:

(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-224, Schedule 1, Page 3 of 4, Line 18
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 8

Line No.	(A)	(B) Year End		(C) Localized Trans. Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Depreciation Expense							
1	Transmission Depreciation					74,843	Sheet 9, Line 12	(a)
2	General Depreciation	4,980,574	Note 4				FF1 page 336 ln. 10, footnote	(a)
3	*less:* Convex-related General Plant Depreciation Expense	1,110,693					Note 1	(a)
4	Subtotal: General Plant Depr Exp, net of Convex (line 2-3)	3,869,881		0.1023%	Note 2	3,959		(a)
5	Total (line 1+4)					78,802		(a)
6	Amortization of Loss on Reacquired Debt	1,309,927		0.0377%	Note 3	494	FF1 page 117 ln. 64	(a)
7	Amortization of Investment Tax Credits	1,511,975		0.0377%	Note 3	570	FF1 page 266 ln. 8 (f)	(a)
8	Property Taxes	120,836,131		0.0377%	Note 3	45,555	FF1 page 263 ln. 24i & 25i	(a)
	Payroll Tax Expense							
9	Federal Unemployment	5,226					FF1 page 262 ln. 3i, footnote	(a)
10	FICA	233,351					FF1 page 262 ln. 5i, footnote	(a)
11	Medicare	65,613					FF1 page 262 ln. 9i, footnote	(a)
12	CT Unemployment	16,786					FF1 page 262 ln. 15i, footnote	(a)
13	MA Unemployment	(285)					FF1 page 262 ln. 32i, footnote	(a)
14	MA Universal Health	64					FF1 page 262 ln. 33i, footnote	(a)
15	NH Unemployment	1,754					FF1 page 262.1 ln. 4i, footnote	(a)
16	NJ Unemployment	-					FF1 page 262 footnote	(a)
17	DC Unemployment	11					FF1 page 262.1 ln. 14i, footnote	(a)
18	FL Unemployment	1					FF1 page 262.1 ln. 18i, footnote	(a)
19	MI Unemployment	6					FF1 page 262.1 ln. 22i, footnote	(a)
20	NY Unemployment	-					FF1 page 262.1 ln. 10i, footnote	(a)
21	Total (Line 9 to 20)	322,527	Note 4	0.1023%	Note 2	330		
	Transmission Operation and Maintenance							
22	Operation and Maintenance	77,432,007					FF1 page 321 ln. 112	(a)
23	Transmission of Electricity by Others - #565	21,727,966					FF1 page 321 ln. 96	(a)
24	Load Dispatching - #561	-					FF1 page 321 ln. 84	(a)
25	Account 561.1	3,245,594					FF1 page 321 ln. 85	(a)
26	Account 561.2	5,212,556					FF1 page 321 ln. 86	(a)
27	Account 561.3	2,238,612					FF1 page 321 ln. 87	(a)
28	Account 561.4	7,157,291					FF1 page 321 ln. 88	(a)
29	O&M (line 22 - lines 23 to 28)	37,849,988		0.1023%	Note 2	38,721		(a)
	Transmission-related Administrative and General							
30	Administrative and General	37,202,294	Note 4				FF1 page 320 ln. 197 b, footnote	(a)
31	**less:** Property Insurance (#924)	763,857	Note 4				FF1 Page 320 ln. 185 b, footnote	(a)
32	**less:** Regulatory Commission Expenses (#928)	2,749,411	Note 4				FF1 page 320 ln. 189 b, footnote	(a)
33	**less:** General Advertising Expense (#930.1)	10,766	Note 4				FF1 page 320 ln. 191 b, footnote	(a)
34	Subtotal (line 30 - lines 31 to 33)	33,678,260		0.1023%	Note 2	34,453		(a)
35	**plus:** Property Insurance	1,413,419		0.0377%	Note 3	533	FF1 page 323 ln. 185	(a)
36	**plus:** Trans. Regulatory Comm. Exp.	2,749,411		0.1023%	Note 2	2,813	FF1 page 320 ln. 189 b, footnote	(a)
37	**plus:** Trans. Related General Advertising Expense	10,766		0.1023%	Note 2	11	FF1 page 320 ln. 191 b, footnote	(a)
38	**plus:** Trans. Related Public Education Expense	-				-	FF1 page 114 ln. 49, footnote	(a)
39	**plus:** Trans. Merger-Related Costs	7,153,326		0.1023%		7,318	Exhibit No. ES-220, Page 1 of 8, Line 2(C)	(b)
40	Total A&G (sum of lines 34 to 38)	45,005,182				45,128		(b)
41	Transmission Related Taxes and Fees	9,854,673		0.1023%	Note 2	10,081	Note 5	(a)

Note 1: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.
Note 5: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment B.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Western Massachusetts Electric Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 1a

Line No.	(A)	Attachment I Reference Section:	(B)	(C) Source	(D) Notes
	I. INVESTMENT BASE				
1	Transmission Plant	II(A)(1)(a)	7,316,798	Sheet 2, Line 5	(a)
2	Transmission Plant Held for Future Use	II(A)(1)(b)	-	Sheet 2, Line 6	(a)
3	Accumulated Depreciation	II(A)(1)(c)	290,421	Sheet 2, Line 11	(a)
4	Accumulated Deferred Income Taxes	II(A)(1)(d)	603,776	Sheet 2, Line 12	(a)
5	Loss On Reacquired Debt	II(A)(1)(e)	2,313	Sheet 2, Line 13	(a)
6	Other Regulatory Assets	II(A)(1)(f)	24,954	Sheet 2, Line 14	(b)
7	Net Investment (Line 1+2-3-4+5)		6,449,868		(b)
8	Prepayments	II(A)(1)(g)	5,502	Sheet 2, Line 15	(a)
9	Materials & Supplies	II(A)(1)(h)	26,259	Sheet 2, Line 16	(a)
10	Cash Working Capital	II(A)(1)(i)	17,521	Sheet 2, Line 23	(b)
11	Total Investment Base (Line 6+7+8+9)		6,499,150		(b)
	II. REVENUE REQUIREMENTS				
12	Investment Return and Income Taxes	II(A)	783,397	Sheet 4a, Line 15(4)	(b)
13	Depreciation Expense	II(B)	184,929	Sheet 8, Line 5	(a)
14	Amortization of Loss on Reacquired Debt	II(C)	323	Sheet 8, Line 6	(a)
15	Investment Tax Credit	II(D)	(154)	Sheet 8, Line 7	(a)
16	Property Tax Expense	II(E)	144,952	Sheet 8, Line 8	(a)
17	Payroll Tax Expense	II(F)	157	Sheet 8, Line 21	(a)
18	Operation & Maintenance Expense	II(G)	54,519	Sheet 8, Line 29	(a)
19	Administrative & General Expense	II(H)	85,648	Sheet 8, Line 39	(b)
20	Support Expenses	II(I)	-		(a)
21	Transmission Related Taxes and Fees	II(J)	177	Sheet 8, Line 40	(a)
22	Total Revenue Requirements (Line 11 thru 20)		1,253,948		(b)

Note:
Investment Return and Income Taxes (line 11 above) was calculated based on the Total Investment Base at 11.07% ROE, plus the Localized PTF Transmission Base (lines 1-3-4) at the .67% capped Incremental ROE.

Notes:

(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247

(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

Western Massachusetts Electric Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 2

Line No.	(A)	(B) Trans. Related Average		(C) Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Transmission Plant							
1	Localized Transmission Plant					7,159,714	Sheet 3, Line 33	(a)
2	Transmission General Plant	18,348,753	Note 4	0.8561%	Note 2	157,084	FF1 page 204 ln. 96, footnote	(a)
3	Total (line 1+2)					7,316,798		(a)
4	Localized Transmission Plant Held for Future Use					-		(a)
	Transmission Accumulated Depreciation							
5	Localized Transmission Accum. Depreciation					256,419	Sheet 9, Line 27(I)	(a)
6	General Plant Accum.Depreciation	3,971,742	Note 4	0.8561%	Note 2	34,002	FF1 page 219 ln. 28, footnote	(a)
7	Total (line 5+6)					290,421		(a)
8								
9	Transmission Accumulated Deferred Taxes					603,776	Sheet 10, Line 46	(a)
10	Unam. Loss on Reacquired Debt (189)	533,928		0.4332%	Note 3	2,313	FF1 page 111 ln. 81	(a)
11	Localized Transmission Other Regulatory Assets	2,914,814		0.8561%		24,954	Exhibit No. ES-220, Page 4 of 8, Line 4(C)	(b)
12	Transmission Prepayments (165)	642,737	Note 4	0.8561%	Note 2	5,502	FF1 page 110 ln. 57, footnote	(a)
13	Transmission Materials and Supplies	3,067,304		0.8561%	Note 2	26,259	FF1 page 227 ln. 8	(a)
	Cash Working Capital							
14	Localized Operation & Maintenance Expense					54,519	Sheet 8, Line 28	(a)
15	Localized Administrative & General Expense					85,648	Sheet 8, Line 39	(c)
16	Subtotal (line 13+14)					140,167		(c)
17	12.5% allowance					0.125	x 45 / 360	(a)
18	Total current Year End (line 15*16)					17,521		(c)
19	Prior Year End Cash Working Capital					17,521		(d)
20	Average Cash Working Capital [(line 17+18)/2]					17,521		(c)

Note 1: Reflects actual information per Eversource's accounting records.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset
(c) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses
(d) Exhibit No. 226, Schedule 3, Page 23 of 26, Line 18(D)

Western Massachusetts Electric Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 4a

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 568,072,183	Note 2	49.54%	4.31%	Note 2	2.14%		
2	PREFERRED STOCK	$ -		0.00%	0.00%		0.00%	0.00%	
3	COMMON EQUITY	$ 578,634,319		50.46%	11.07%	Note 1	5.59%	5.59%	
4	TOTAL INVESTMENT RETURN	$ 1,146,706,502		100.00%			7.73%	5.59%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 7.73% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate)) / Total Inv. Base)) * Federal Income Tax Rate)

Line		Line 4, Col. (5)		Sheet 8, Line 7		Sheet 6, Line 1		Sheet 1, Line 10		Federal Corporate Tax Rate	
6	Source: = ((	5.59%	+ ((	(154)	+	1,593	) /	6,499,150	)) *	35.00%	)
7			(	1	-	35.00%	)				
						Federal Corporate Tax Rate					
8	=	3.0219%									

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate)) / Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)

Line		Line 4, Col. (5)		Sheet 8, Line 7		Sheet 6, Line 1		Sheet 1, Line 10		Line 8, Col. (1)		Massachusetts Corporate Tax Rate	
9	Source: = ((	5.59%	+ ((	(154)	+	1,593	) /	6,499,150	) +	3.0219%	) *	8.00%	)
10			(	1	-	8.00%	)						
						Massachusetts Corporate Tax Rate							
11	=	0.7508%											

12 (a)+(b)+(c) **Cost of Capital Rate** = 11.5027%

Line			
13	INVESTMENT BASE	6,499,150	Sheet 1, Line 10
14			
15	x Cost of Capital Rate	11.5027%	Line 12, Col. (1)
16	= Investment Return and Income Taxes	$ 747,578	

Total Investment Return and Income Taxes		
@11.07%	$ 747,578	Line 16, Col. (1)
@.67%	$ 35,819	Sheet 5, Line 17
	$ 783,397	To Sheet 1a, Line 11

Note 1: ROE per FERC Order in Docket No. ER04-157 dated March 24, 2008.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes:

(1) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Western Massachusetts Electric Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 568,072,183	Note 2	49.54%					
2	PREFERRED STOCK	$ -		0.00%					
3	COMMON EQUITY	$ 578,634,319		50.46%	0.50%	Note 1	0.25%	0.25%	
4	TOTAL INVESTMENT RETURN	$ 1,146,706,502		100.00%			0.25%	0.25%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.25% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate)) / Total Inv. Base)) * Federal Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Federal Corporate Tax Rate

6 = ((0.25% + ((0 + 0) / 6,499,150)) * 35.00%)
7 (1 - 35.00%) Federal Corporate Tax Rate

8 = 0.1346%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate)) / Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Line 8, Col. (1); Massachusetts Corporate Tax Rate

9 = ((0.25% + ((0 + 0) / 6,499,150) + 0.1346%) * 8.00%)
10 (1 - 8.00%) Massachusetts Corporate Tax Rate

11 = 0.0334%

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.4180%

13 INVESTMENT BASE 6,499,150 Line 16, Col. (4)

14 x Cost of Capital Rate 0.4180% Line 12, Col. (1)

15 = Investment Return and Income Taxes $ 27,166 to Sheet 4a, Line 14(4)

Note 1: CAP on ROE incentives per FERC Order in Docket No. EL11-66 dated March 3, 2015.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.

Notes:

(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-224, Schedule 1, Page 3 of 4, Line 18
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Western Massachusetts Electric Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 8

Line No.	(A)	(B) Year End		(C) Localized Trans. Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Depreciation Expense							
1	Transmission Depreciation					178,169	Sheet 9, Line 29	(a)
2	General Depreciation	789,658	Note 4	0.8561%	Note 2	6,760	FF1 page 336 ln. 10, footnote	(a)
3	Total (line 1+4)					184,929		(a)
4								(a)
								(a)
5	Amortization of Loss on Reacquired Debt	74,501		0.4332%	Note 3	323	FF1 pg 117 ln. 64	
								(a)
6	Amortization of Investment Tax Credits	35,604		0.4332%	Note 3	154	FF1 page 266 ln. 8(f), footnote	
								(a)
7	Property Taxes	33,460,690		0.4332%	Note 3	144,952	FF1 page 263 ln. 31i & 32i	
								(a)
	Payroll Tax Expense							
8	Federal Unemployment	283					FF1 page 262 ln. 3i, footnote	
9	FICA	13,202					FF1 page 262 ln. 5i, footnote	(a)
10	Medicare	3,757					FF1 page 262 ln. 9i, footnote	(a)
11	CT Unemployment	852					FF1 page 262 ln. 13i, footnote	(a)
12	MA Unemployment	69					FF1 page 262 ln. 22i, footnote	(a)
13	MA Universal Health	19					FF1 page 262 ln. 27i, footnote	(a)
14	NH Unemployment	108					FF1 page 262 ln. 37i, footnote	(a)
15	NJ Unemployment	-					FF1 page 262, footnote	(a)
16	DC Unemployment	1					FF1 page 262.1 ln. 6i, footnote	(a)
17	FL Unemployment	-					FF1 page 262, footnote	(a)
18	MI Unemployment	-					FF1 page 262, footnote	(a)
19	NY Unemployment	-					FF1 page 262, footnote	(a)
20	Total (Line 9 to 20)	18,291	Note 4	0.8561%	Note 2	157		(a)
	Transmission Operation and Maintenance							
21	Operation and Maintenance	20,725,279					FF1 page 321 ln. 112	
22	Transmission of Electricity by Others - #565	13,174,678					FF1 page 321 ln. 96	(a)
23	Load Dispatching - #561	-					FF1 page 321 ln. 84	(a)
24	Account 561.1	12,368					FF1 page 321 ln. 85	(a)
25	Account 561.2	50,569					FF1 page 321 ln. 86	(a)
26	Account 561.3	13,262					FF1 page 321 ln. 87	(a)
27	Account 561.4	1,106,108					FF1 page 321 ln. 88	(a)
28	O&M (line 22 - lines 23 to 28)	6,368,294		0.8561%	Note 2	54,519		(a)
								(a)
	Transmission-related Administrative and General							
29	Administrative and General	8,041,502	Note 4				FF1 page 320 ln. 197, footnote	(a)
30	**less:** Property Insurance (#924)	106,141	Note 4				FF1 Page 320 ln. 185 b, footnote	(a)
31	**less:** Regulatory Commission Expenses (#928)	563,123	Note 4				FF1 page 320 ln. 189 b, footnote	(a)
32	**less:** General Advertising Expense (#930.1)	2,857	Note 4				FF1 page 320 ln. 191 b, footnote	(a)
33	Subtotal (line 30 - lines 31 to 33)	7,369,381		0.8561%	Note 2	63,089		(a)
34	**plus:** Property Insurance	248,747		0.4332%	Note 3	1,078	FF1 page 323 ln. 185	(a)
35	**plus:** Trans. Regulatory Comm. Exp.	563,123		0.8561%	Note 2	4,821	FF1 page 320 ln. 189 b, footnote	(a)
36	**plus:** Trans. Related General Advertising Expense	2,857		0.8561%	Note 2	24	FF1 page 320 ln. 191 b, footnote	(a)
37	**plus:** Trans. Related Public Education Expense	-				-	FF1 page 114 ln. 49, footnote	(a)
38	plus: Trans. Merger-Related Costs	1,943,209		0.8561%		16,636	Exhibit No. ES-220, Page 4 of 8, Line 2(C)	(b)
39	Total A&G (sum of lines 34 to 38)	10,127,317				85,648	Exhibit No. ES-220, Page 1 of 8, Line 2	(b)
40	Transmission Related Taxes and Fees	20,627		0.8561%	Note 2	177	Note 5	
								(a)

Note 1: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.
Note 5: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment B.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Exhibit No. ES-226
Schedule 4

Category B Revenue Requirements under the Changed Rates for 2018

Eversource Energy Service Company

CL&P and WMECO
ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Estimated Schedule 21-ES (Formerly Schedule 21-NU) Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I) of the ISO-NE OATT
For the Calendar year 2018

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)=(C)+(D)+(E)+(F)+(G)
			CL&P				WMECO	
Line	Description	Reference	B-N	M-N	G-C	GSRP	GSRP	Total
1	2014 Actual Schedule 21-ES, Category B Rev. Req.		$ 19,541,764 (1)	$ 10,323,238 (2)	$ 4,304,534 (3)	$ 588,155 (4)	$ 1,252,041 (5)	$ 36,009,732
2	Estimated 2015 Plant Additions	(6)	$ -	$ -	$ -	$ -	$ -	$ -
3	Carrying Charge Factor (CCF)	(6)	0.00%	0.00%	0.00%	0.00%	0.00%	
4	2015 Incremental Estimated Schedule 21-ES, Cat. B Rev. Req.	Line 2 x 3	-	-	-	-	-	$ -
5	Total Estimated Schedule 21-ES, Cat. B Revenue Requirement for 2015	Line 1 + 4	$ 19,541,764	$ 10,323,238	$ 4,304,534	$ 588,155	$ 1,252,041	$ 36,009,732
6	Estimated 2016 Plant Additions	(6)	$ -	$ -	$ -	$ -	$ -	$ -
7	Carrying Charge Factor (CCF)	(6)	0.00%	0.00%	0.00%	0.00%	0.00%	
8	2016 Incremental Estimated Schedule 21-ES, Cat. B Rev. Req.	Line 7 x 8	-	-	-	-	-	$ -
9	Total Estimated Schedule 21-ES, Cat. B Revenue Requirement for 2016	Line 6 + 9	$ 19,541,764	$ 10,323,238	$ 4,304,534	$ 588,155	$ 1,252,041	$ 36,009,732 (7)

Notes:

(1) Exhibit No. ES-226, Schedule 3, Page 2 of 26, Line 22(B)
(2) Exhibit No. ES-226, Schedule 3, Page 7 of 26, Line 22(B)
(3) Exhibit No. ES-226, Schedule 3, Page 12 of 26, Line 22(B)
(4) Exhibit No. ES-226, Schedule 3, Page 17 of 26, Line 22(B)
(5) Exhibit No. ES-226, Schedule 3, Page 22 of 26, Line 22(B)
(6) These are no forecasted plant additions for Category B
(7) The revenue requirements calculations for the calendar year 2016 (including any forecast for 2016) are used as an estimate for the revenue requirements for 2018, which are used to calculate the revenue impact of the proposed cost recovery.

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Bethel-Norwalk
Sheet 1a

Line No.	(A)	Attachment I Reference Section:	(B)	(C) Source	(D) Notes
	I. INVESTMENT BASE				
1	Transmission Plant	II(A)(1)(a)	125,258,704	Sheet 2, Line 5	(a)
2	Transmission Plant Held for Future Use	II(A)(1)(b)	-	Sheet 2, Line 6	(a)
3	Accumulated Depreciation	II(A)(1)(c)	23,816,817	Sheet 2, Line 11	(a)
4	Accumulated Deferred Income Taxes	II(A)(1)(d)	19,494,337	Sheet 2, Line 12	(a)
5	Loss On Reacquired Debt	II(A)(1)(e)	187,920	Sheet 2, Line 13	(a)
6	Other Regulatory Assets	II(A)(1)(f)	144,522	Sheet 2, Line 14	(b)
7	Net Investment (Line 1+2-3-4+5)		82,279,992		(b)
8	Prepayments	II(A)(1)(g)	787,415	Sheet 2, Line 15	(a)
9	Materials & Supplies	II(A)(1)(h)	1,459,628	Sheet 2, Line 16	(a)
10	Cash Working Capital	II(A)(1)(i)	413,987	Sheet 2, Line 23	(b)
11	Total Investment Base (Line 6+7+8+9)		84,941,022		(b)
	II. REVENUE REQUIREMENTS				
12	Investment Return and Income Taxes	II(A)	10,968,234	Sheet 4a, Line 15(4)	(b)
13	Depreciation Expense	II(B)	3,051,146	Sheet 8, Line 5	(a)
14	Amortization of Loss on Reacquired Debt	II(C)	19,538	Sheet 8, Line 6	(a)
15	Investment Tax Credit	II(D)	(22,551)	Sheet 8, Line 7	(a)
16	Property Tax Expense	II(E)	1,802,271	Sheet 8, Line 8	(a)
17	Payroll Tax Expense	II(F)	13,032	Sheet 8, Line 21	(a)
18	Operation & Maintenance Expense	II(G)	1,529,404	Sheet 8, Line 29	(a)
19	Administrative & General Expense	II(H)	1,782,492	Sheet 8, Line 40	(b)
20	Support Expenses	II(I)	-		(a)
21	Transmission Related Taxes and Fees	II(J)	398,198	Sheet 8, Line 41	(a)
22	Total Revenue Requirements (Line 11 thru 20)		19,541,764		(b)

Note:
Investment Return and Income Taxes (line 11 above) was calculated based on the Total Investment Base at 11.07% ROE, plus the Localized Post-2003 PTF Transmission Base (lines 1-3-4) at the .67% capped Incremental ROE.

Notes:

(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247

(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Bethel-Norwalk
Sheet 2

Line No.	(A)	(B) Trans. Related Average		(C) Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Transmission Plant							
1	Localized Transmission Plant					121,745,648	Sheet 3, Line 19	(a)
2	Transmission General Plant	102,812,641	Note 4				FF1 page 204 ln. 96, footnote	(a)
3	Less: Convex-related General Plant	15,870,872					Note 1	(a)
4	Subtotal: General Plant, net of Convex (line 2 - 3)	86,941,769		4.0407%	Note 2	3,513,056		(a)
5	Total (line 1+4)					125,258,704		(a)
6	Localized Transmission Plant Held for Future Use					-		(a)
	Transmission Accumulated Depreciation							
7	Localized Transmission Accum. Depreciation					22,912,990	Sheet 9, Line 56(I)	(a)
8	General Plant Accum. Depreciation	26,085,325	Note 4				FF1 page 219 ln. 28, footnote	(a)
9	Less: Convex-related General Plant Acc Depr	3,717,252					Note 1	(a)
10	Subtotal: General Plant A/D, net of Convex (line 8-9)	22,368,074		4.0407%	Note 2	903,827		(a)
11	Total (line 7+10)					23,816,817		(a)
12	Transmission Accumulated Deferred Taxes					19,494,337	Sheet 10, Line 111	(a)
13	Unam. Loss on Reacquired Debt (189)	12,599,425		1.4915%	Note 3	187,920	FF1 page 111 ln. 81	(a)
14	Localized Transmission Other Regulatory Assets	3,576,663		4.0407%		144,522	Exhibit No. ES-220, Page 1 of 8, Line 4(D)	(b)
15	Transmission Prepayments (165)	19,487,085	Note 4	4.0407%	Note 2	787,415	FF1 page 110 ln. 57, footnote	(a)
16	Transmission Materials and Supplies	36,123,136		4.0407%	Note 2	1,459,628	FF1 page 227 ln. 8	(a)
	Cash Working Capital							
17	Localized Operation & Maintenance Expense					1,529,404	Sheet 8, Line 29	(a)
18	Localized Administrative & General Expense					1,782,492	Sheet 8, Line 40	(c)
19	Subtotal (line 16+17)					3,311,896		(c)
20	12.5% allowance					0.125	x 45 / 360	(a)
21	Total current Year End (line 18*19)					413,987		(c)
22	Prior Year End Cash Working Capital					413,987		(d)
23	Average Cash Working Capital [(line 20+21)/2]					413,987		(c)

Note 1: Reflects actual information per Eversource's accounting records.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset
(c) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses
(d) Exhibit No. 226, Schedule 4, Page 3 of 26, Line 21(D)

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Bethel-Norwalk
Sheet 4a

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559	Note 2	46.27%	5.36%	Note 2	2.48%		
2	PREFERRED STOCK	$ 116,842,775		2.14%	4.80%		0.10%	0.10%	
3	COMMON EQUITY	$ 2,820,159,065		51.59%	11.07%	Note 1	5.71%	5.71%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399		100.00%			8.29%	5.81%	

Cost of Capital Rate=

Line	Description													
5	(a) Weighted Cost of Capital	=	8.29%	Line 4, Col. (4)										
					Total Inv.		Eq. AFUDC							
	(b) Federal Income Tax	= ((	R.O.E.	+ ((	(Tax Credit)	+	of Deprec. Exp.	) /	Total Inv. Base	)) *	Federal Income Tax Rate	)		
				(	1	-	Federal Income Tax Rate	)						
		Source:	Line 4, Col. (5)		Sheet 8, Line 7		Sheet 6, Line 1		Sheet 1, Line 10		Federal Corporate Tax Rate			
6		= ((	5.81%	+ ((	(22,551)	+	93,235	) /	84,941,022	)) *	35.00%	)		
7				(	1	-	35.00%	)						
							Federal Corporate Tax Rate							
8		=	3.1733%											
					Total Inv.		Eq. AFUDC							
	(c) State Income Tax	= ((	R.O.E.	+ ((	(Tax Credit)	+	of Deprec. Exp.	) /	Total Inv. Base	) +	Federal Income Tax	) *	State Income Tax Rate	)
				(	1	-	State Income Tax Rate	)						
		Source:	Line 4, Col. (5)		Sheet 8, Line 7		Sheet 6, Line 1		Sheet 1, Line 10		Line 8, Col. (1)		Connecticut Corporate Tax Rate	
9		= ((	5.81%	+ ((	(22,551)	+	93,235	) /	84,941,022	) +	3.1733%	) *	9.00%	)
10				(	1	-	9.00%	)						
							Connecticut Corporate Tax Rate							
11		=	0.8967%											
12	(a)+(b)+(c) **Cost of Capital Rate**	=	12.3600%											

Line			
13	INVESTMENT BASE	84,941,022	Sheet 1, Line 10
14			
15	x Cost of Capital Rate	12.3600%	Line 12, Col. (1)
16	= Investment Return and Income Taxes	$ 10,498,710	

Total Investment Return and Income Taxes		
@11.07%	$ 10,498,710	Line 16, Col. (1)
@.67%	$ 469,524	Sheet 5a, Line 17
	$ 10,968,234	To Sheet 1a, Line 11

Note 1: ROE per FERC Order in Docket No. ER11-66 dated October 16, 2014.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes:

(1) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Bethel-Norwalk

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559	Note 2	46.27%					
2	PREFERRED STOCK	$ 116,842,775		2.14%					
3	COMMON EQUITY	$ 2,820,159,065		51.59%	0.50%	Note 1	0.26%	0.26%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399		100.00%			0.26%	0.26%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.26% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / Total Inv. Base)) * Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Federal Corporate Tax Rate

6 = ((0.26% + ((0 + 0) / 84,941,022)) * 35.00%)
7 (1 - 35.00%) Federal Corporate Tax Rate

8 = 0.1400%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / Total Inv. Base) + Federal Income Tax) * State Income Tax Rate) / (1 - State Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Line 8, Col. (1); Connecticut Corporate Tax Rate

9 = ((0.26% + ((0 + 0) / 84,941,022) + 0.1400%) * 9.00%)
10 (1 - 9.00%) Connecticut Corporate Tax Rate

11 = 0.0396%

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.4396%

13 INVESTMENT BASE 84,941,022 Line 16, Col. (4)

14 x Cost of Capital Rate 0.4396% Line 12, Col. (1)

15 = Investment Return and Income Taxes $ 373,401 to Sheet 4a, Line 14(4)

Note 1: CAP on ROE incentives per FERC Order in Docket No. EL11-66 dated March 3, 2015.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.

Notes:

(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-224, Schedule 1, Page 4 of 4, Line 18
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Bethel-Norwalk
Sheet 8

Line No.	(A)	(B) Year End		(C) Localized Trans. Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Depreciation Expense							
1	Transmission Depreciation					2,894,776	Sheet 9, Line 58	(a)
2	General Depreciation	4,980,574	Note 4				FF1 page 336 ln. 10, footnote	(a)
3	*less:* Convex-related General Plant Depreciation Expense	1,110,693					Note 1	(a)
4	Subtotal: General Plant Depr Exp, net of Convex (line 2-3)	3,869,881		4.0407%	Note 2	156,370		(a)
5	Total (line 1+4)					3,051,146		(a)
6	Amortization of Loss on Reacquired Debt	1,309,927		1.4915%	Note 3	19,538	FF1 page 117 ln. 64	(a)
7	Amortization of Investment Tax Credits	1,511,975		1.4915%	Note 3	22,551	FF1 page 266 ln. 8 (f)	(a)
8	Property Taxes	120,836,131		1.4915%	Note 3	1,802,271	FF1 page 263 ln. 24i & 25i	(a)
	Payroll Tax Expense							
9	Federal Unemployment	5,226					FF1 page 262 ln. 3i, footnote	(a)
10	FICA	233,351					FF1 page 262 ln. 5i, footnote	(a)
11	Medicare	65,613					FF1 page 262 ln. 9i, footnote	(a)
12	CT Unemployment	16,786					FF1 page 262 ln. 15i, footnote	(a)
13	MA Unemployment	(285)					FF1 page 262 ln. 32i, footnote	(a)
14	MA Universal Health	64					FF1 page 262 ln. 33i, footnote	(a)
15	NH Unemployment	1,754					FF1 page 262.1 ln. 4i, footnote	(a)
16	NJ Unemployment	-					FF1 page 262 footnote	(a)
17	DC Unemployment	11					FF1 page 262.1 ln. 14i, footnote	(a)
18	FL Unemployment	1					FF1 page 262.1 ln. 18i, footnote	(a)
19	MI Unemployment	6					FF1 page 262.1 ln. 22i, footnote	(a)
20	NY Unemployment	-					FF1 page 262.1 ln. 10i, footnote	(a)
21	Total (Line 9 to 20)	322,527	Note 4	4.0407%	Note 2	13,032		
	Transmission Operation and Maintenance							
22	Operation and Maintenance	77,432,007					FF1 page 321 ln. 112	(a)
23	Transmission of Electricity by Others - #565	21,727,966					FF1 page 321 ln. 96	(a)
24	Load Dispatching - #561	-					FF1 page 321 ln. 84	(a)
25	Account 561.1	3,245,594					FF1 page 321 ln. 85	(a)
26	Account 561.2	5,212,556					FF1 page 321 ln. 86	(a)
27	Account 561.3	2,238,612					FF1 page 321 ln. 87	(a)
28	Account 561.4	7,157,291					FF1 page 321 ln. 88	(a)
29	O&M (line 22 - lines 23 to 28)	37,849,988		4.0407%	Note 2	1,529,404		(a)
	Transmission-related Administrative and General							
30	Administrative and General	37,202,294	Note 4				FF1 page 320 ln. 197 b, footnote	(a)
31	**less:** Property Insurance (#924)	763,857	Note 4				FF1 Page 320 ln. 185 b, footnote	(a)
32	**less:** Regulatory Commission Expenses (#928)	2,749,411	Note 4				FF1 page 320 ln. 189 b, footnote	(a)
33	**less:** General Advertising Expense (#930.1)	10,766	Note 4				FF1 page 320 ln. 191 b, footnote	(a)
34	Subtotal (line 30 - lines 31 to 33)	33,678,260		4.0407%	Note 2	1,360,837		(a)
35	**plus:** Property Insurance	1,413,419		1.4915%	Note 3	21,081	FF1 page 323 ln. 185	(a)
36	**plus:** Trans. Regulatory Comm. Exp.	2,749,411		4.0407%	Note 2	111,095	FF1 page 320 ln. 189 b, footnote	(a)
37	**plus:** Trans. Related General Advertising Expense	10,766		4.0407%	Note 2	435	FF1 page 320 ln. 191 b, footnote	(a)
38	**plus:** Trans. Related Public Education Expense	-				-	FF1 page 114 ln. 49, footnote	(a)
39	**plus:** Trans. Merger-Related Costs	7,153,326		4.0407%		289,044	Exhibit No. ES-220, Page 1 of 8, Line 2(D)	(b)
40	Total A&G (sum of lines 34 to 38)	45,005,182				1,782,492		(b)
41	Transmission Related Taxes and Fees	9,854,673		4.0407%	Note 2	398,198	Note 5	(a)

Note 1: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.
Note 5: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment B.

Notes:

(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Middletown-Norwalk
Sheet 1a

Line No.	(A)	Attachment I Reference Section:	(B)	(C) Source	(D) Notes
	I. INVESTMENT BASE				
1	Transmission Plant	II(A)(1)(a)	62,028,638	Sheet 2, Line 5	(a)
2	Transmission Plant Held for Future Use	II(A)(1)(b)	-	Sheet 2, Line 6	(a)
3	Accumulated Depreciation	II(A)(1)(c)	9,382,562	Sheet 2, Line 11	(a)
4	Accumulated Deferred Income Taxes	II(A)(1)(d)	7,626,580	Sheet 2, Line 12	(a)
5	Loss On Reacquired Debt	II(A)(1)(e)	93,059	Sheet 2, Line 13	(a)
6	Other Regulatory Assets	II(A)(1)(f)	71,569	Sheet 2, Line 14	(b)
7	Net Investment (Line 1+2-3-4+5)		45,184,124		(b)
8	Prepayments	II(A)(1)(g)	389,937	Sheet 2, Line 15	(a)
9	Materials & Supplies	II(A)(1)(h)	722,824	Sheet 2, Line 16	(a)
10	Cash Working Capital	II(A)(1)(i)	205,011	Sheet 2, Line 23	(b)
11	Total Investment Base (Line 6+7+8+9)		46,501,896		(b)
	II. REVENUE REQUIREMENTS				
12	Investment Return and Income Taxes	II(A)	6,003,856	Sheet 4a, Line 15(4)	(b)
13	Depreciation Expense	II(B)	1,584,643	Sheet 8, Line 5	(a)
14	Amortization of Loss on Reacquired Debt	II(C)	9,675	Sheet 8, Line 6	(a)
15	Investment Tax Credit	II(D)	(11,167)	Sheet 8, Line 7	(a)
16	Property Tax Expense	II(E)	892,496	Sheet 8, Line 8	(a)
17	Payroll Tax Expense	II(F)	6,454	Sheet 8, Line 21	(a)
18	Operation & Maintenance Expense	II(G)	757,378	Sheet 8, Line 29	(a)
19	Administrative & General Expense	II(H)	882,711	Sheet 8, Line 40	(b)
20	Support Expenses	II(I)	-		(a)
21	Transmission Related Taxes and Fees	II(J)	197,192	Sheet 8, Line 41	(a)
22	Total Revenue Requirements (Line 11 thru 20)		10,323,238		(b)

Note:
Investment Return and Income Taxes (line 11 above) was calculated based on the Total Investment Base at 11.07% ROE, plus the Localized Post-2003 PTF Transmission Base (lines 1-3-4) at the .67% capped Incremental ROE.

Notes:

(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247

(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Middletown-Norwalk
Sheet 2

Line No.	(A)	(B) Trans. Related Average		(C) Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Transmission Plant							
1	Localized Transmission Plant					60,288,933	Sheet 3, Line 18	(a)
2	Transmission General Plant	102,812,641	Note 4				FF1 page 204 ln. 96, footnote	(a)
3	Less: Convex-related General Plant	15,870,872					Note 1	(a)
4	Subtotal: General Plant, net of Convex (line 2 - 3)	86,941,769		2.0010%	Note 2	1,739,705		(a)
5	Total (line 1+4)					62,028,638		(a)
6	Localized Transmission Plant Held for Future Use					-		(a)
	Transmission Accumulated Depreciation							
7	Localized Transmission Accum. Depreciation					8,934,977	Sheet 9, Line 84(I)	(a)
8	General Plant Accum. Depreciation	26,085,325	Note 4				FF1 page 219 ln. 28, footnote	(a)
9	Less: Convex-related General Plant Acc Depr	3,717,252					Note 1	(a)
10	Subtotal: General Plant A/D, net of Convex (line 8-9)	22,368,074		2.0010%	Note 2	447,585		(a)
11	Total (line 7+10)					9,382,562		(a)
12	Transmission Accumulated Deferred Taxes					7,626,580	Sheet 10, Line 105	(a)
13	Unam. Loss on Reacquired Debt (189)	12,599,425		0.7386%	Note 3	93,059	FF1 page 111 ln. 81	(a)
14	Localized Transmission Other Regulatory Assets	3,576,663		2.0010%		71,569	Exhibit No. ES-220, Page 1 of 8, Line 4(D)	(b)
15	Transmission Prepayments (165)	19,487,085	Note 4	2.0010%	Note 2	389,937	FF1 page 110 ln. 57, footnote	(a)
16	Transmission Materials and Supplies	36,123,136		2.0010%	Note 2	722,824	FF1 page 227 ln. 8	(a)
	Cash Working Capital							
17	Localized Operation & Maintenance Expense					757,378	Sheet 8, Line 29	(a)
18	Localized Administrative & General Expense					882,711	Sheet 8, Line 40	(c)
19	Subtotal (line 16+17)					1,640,089		(c)
20	12.5% allowance					0.125	x 45 / 360	(a)
21	Total current Year End (line 18*19)					205,011		(c)
22	Prior Year End Cash Working Capital					205,011		(d)
23	Average Cash Working Capital [(line 20+21)/2]					205,011		(c)

Note 1: Reflects actual information per Eversource's accounting records.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.

Notes:

(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset
(c) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses
(d) Exhibit No. 226, Schedule 4, Page 8 of 26, Line 21(D)

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Middletown-Norwalk
Sheet 4a

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559	Note 2	46.27%	5.36%	Note 2	2.48%		
2	PREFERRED STOCK	$ 116,842,775		2.14%	4.80%		0.10%	0.10%	
3	COMMON EQUITY	$ 2,820,159,065		51.59%	11.07%	Note 1	5.71%	5.71%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399		100.00%			8.29%	5.81%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 8.29% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / Total Inv. Base)) * Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

	Source:	Line 4, Col. (5)		Sheet 8, Line 7		Sheet 6, Line 1		Sheet 1, Line 10		Federal Corporate Tax Rate	
6	= ((	5.81%	+ ((	(11,167)	+	46,171	) /	46,501,896	)) *	35.00%	)
7			(	1	-	35.00%	)				
						Federal Corporate Tax Rate					

8 = 3.1690%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / Total Inv. Base) + Federal Income Tax) * State Income Tax Rate) / (1 - State Income Tax Rate)

	Source:	Line 4, Col. (5)		Sheet 8, Line 7		Sheet 6, Line 1		Sheet 1, Line 10		Line 8, Col. (1)		Connecticut Corporate Tax Rate	
9	= ((	5.81%	+ ((	(11,167)	+	46,171	) /	46,501,896	) +	3.1690%	) *	9.00%	)
10			(	1	-	9.00%	)						
						Connecticut Corporate Tax Rate							

11 = 0.8955%

12 (a)+(b)+(c) **Cost of Capital Rate** = 12.3545%

Line			
13	INVESTMENT BASE	46,501,896	Sheet 1, Line 10
14			
15	x Cost of Capital Rate	12.3545%	Line 12, Col. (1)
16	= Investment Return and Income Taxes	$ 5,745,077	

Total Investment Return and Income Taxes			
@11.07%	$	5,745,077	Line 16, Col. (1)
@.67%	$	258,779	Sheet 5a, Line 17
	$	6,003,856	To Sheet 1a, Line 11

Note 1: ROE per FERC Order in Docket No. ER11-66 dated October 16, 2014.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes:

(1) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Middletown-Norwalk
Sheet 5a

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559	Note 2	46.27%					
2	PREFERRED STOCK	$ 116,842,775		2.14%					
3	COMMON EQUITY	$ 2,820,159,065		51.59%	0.50%	Note 1	0.26%	0.26%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399		100.00%			0.26%	0.26%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.26% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate) / Total Inv. Base)) * Federal Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Federal Corporate Tax Rate

6 = ((0.26% + ((0 + 0) / 46,501,896)) * 35.00%)
7 (1 - 35.00%) Federal Corporate Tax Rate

8 = 0.1400%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate) / Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Line 8, Col. (1); Connecticut Corporate Tax Rate

9 = ((0.26% + ((0 + 0) / 46,501,896) + 0.1400%) * 9.00%)
10 (1 - 9.00%) Connecticut Corporate Tax Rate

11 = 0.0396%

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.4396%

13 INVESTMENT BASE 46,501,896 Line 16, Col. (4)

14 x Cost of Capital Rate 0.4396% Line 12, Col. (1)

15 = Investment Return and Income Taxes $ 204,422 to Sheet 4a, Line 14(4)

Note 1: CAP on ROE incentives per FERC Order in Docket No. EL11-66 dated March 3, 2015.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.

Notes:

(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-224, Schedule 1, Page 4 of 4, Line 18
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Middletown-Norwalk
Sheet 8

Line No.	(A)	(B) Year End		(C) Localized Trans. Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Depreciation Expense							
1	Transmission Depreciation					1,507,207	Sheet 9, Line 86	(a)
2	General Depreciation	4,980,574	Note 4				FF1 page 336 ln. 10, footnote	(a)
3	*less:* Convex-related General Plant Depreciation Expense	1,110,693					Note 1	(a)
4	Subtotal: General Plant Depr Exp, net of Convex (line 2-3)	3,869,881		2.0010%	Note 2	77,436		(a)
5	Total (line 1+4)					1,584,643		(a)
6	Amortization of Loss on Reacquired Debt	1,309,927		0.7386%	Note 3	9,675	FF1 page 117 ln. 64	(a)
7	Amortization of Investment Tax Credits	1,511,975		0.7386%	Note 3	11,167	FF1 page 266 ln. 8 (f)	(a)
8	Property Taxes	120,836,131		0.7386%	Note 3	892,496	FF1 page 263 ln. 24i & 25i	(a)
	Payroll Tax Expense							
9	Federal Unemployment	5,226					FF1 page 262 ln. 3i, footnote	(a)
10	FICA	233,351					FF1 page 262 ln. 5i, footnote	(a)
11	Medicare	65,613					FF1 page 262 ln. 9i, footnote	(a)
12	CT Unemployment	16,786					FF1 page 262 ln. 15i, footnote	(a)
13	MA Unemployment	(285)					FF1 page 262 ln. 32i, footnote	(a)
14	MA Universal Health	64					FF1 page 262 ln. 33i, footnote	(a)
15	NH Unemployment	1,754					FF1 page 262.1 ln. 4i, footnote	(a)
16	NJ Unemployment	-					FF1 page 262 footnote	(a)
17	DC Unemployment	11					FF1 page 262.1 ln. 14i, footnote	(a)
18	FL Unemployment	1					FF1 page 262.1 ln. 18i, footnote	(a)
19	MI Unemployment	6					FF1 page 262.1 ln. 22i, footnote	(a)
20	NY Unemployment	-					FF1 page 262.1 ln. 10i, footnote	(a)
21	Total (Line 9 to 20)	322,527	Note 4	2.0010%	Note 2	6,454		
	Transmission Operation and Maintenance							
22	Operation and Maintenance	77,432,007					FF1 page 321 ln. 112	(a)
23	Transmission of Electricity by Others - #565	21,727,966					FF1 page 321 ln. 96	(a)
24	Load Dispatching - #561	-					FF1 page 321 ln. 84	(a)
25	Account 561.1	3,245,594					FF1 page 321 ln. 85	(a)
26	Account 561.2	5,212,556					FF1 page 321 ln. 86	(a)
27	Account 561.3	2,238,612					FF1 page 321 ln. 87	(a)
28	Account 561.4	7,157,291					FF1 page 321 ln. 88	(a)
29	O&M (line 22 - lines 23 to 28)	37,849,988		2.0010%	Note 2	757,378		(a)
	Transmission-related Administrative and General							
30	Administrative and General	37,202,294	Note 4				FF1 page 320 ln. 197 b, footnote	(a)
31	**less:** Property Insurance (#924)	763,857	Note 4				FF1 Page 320 ln. 185 b, footnote	(a)
32	**less:** Regulatory Commission Expenses (#928)	2,749,411	Note 4				FF1 page 320 ln. 189 b, footnote	(a)
33	**less:** General Advertising Expense (#930.1)	10,766	Note 4				FF1 page 320 ln. 191 b, footnote	(a)
34	Subtotal (line 30 - lines 31 to 33)	33,678,260		2.0010%	Note 2	673,902		(a)
35	**plus:** Property Insurance	1,413,419		0.7386%	Note 3	10,440	FF1 page 323 ln. 185	(a)
36	**plus:** Trans. Regulatory Comm. Exp.	2,749,411		2.0010%	Note 2	55,016	FF1 page 320 ln. 189 b, footnote	(a)
37	**plus:** Trans. Related General Advertising Expense	10,766		2.0010%	Note 2	215	FF1 page 320 ln. 191 b, footnote	(a)
38	**plus:** Trans. Related Public Education Expense	-				-	FF1 page 114 ln. 49, footnote	(a)
39	**plus:** Trans. Merger-Related Costs	7,153,326		2.0010%		143,138	Exhibit No. ES-220, Page 1 of 8, Line 2(D)	(b)
40	Total A&G (sum of lines 34 to 38)	45,005,182				882,711		(b)
41	Transmission Related Taxes and Fees	9,854,673		2.0010%	Note 2	197,192	Note 5	(a)

Note 1: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.
Note 5: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment B.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Glenbrook Cables
Sheet 1a

Line No.	(A)	Attachment I Reference Section:	(B)	(C) Source	(D) Notes
	I. INVESTMENT BASE				
1	Transmission Plant	II(A)(1)(a)	2,644,161	Sheet 2, Line 5	(a)
2	Transmission Plant Held for Future Use	II(A)(1)(b)	31,396,972	Sheet 2, Line 6	(a)
3	Accumulated Depreciation	II(A)(1)(c)	353,497	Sheet 2, Line 11	(a)
4	Accumulated Deferred Income Taxes	II(A)(1)(d)	323,209	Sheet 2, Line 12	(a)
5	Loss On Reacquired Debt	II(A)(1)(e)	3,969	Sheet 2, Line 13	(a)
6	Other Regulatory Assets	II(A)(1)(f)	3,051	Sheet 2, Line 14	(b)
7	Net Investment (Line 1+2-3-4+5)		33,371,447		(b)
8	Prepayments	II(A)(1)(g)	16,622	Sheet 2, Line 15	(a)
9	Materials & Supplies	II(A)(1)(h)	30,813	Sheet 2, Line 16	(a)
10	Cash Working Capital	II(A)(1)(i)	8,739	Sheet 2, Line 23	(b)
11	Total Investment Base (Line 6+7+8+9)		33,427,621		(b)
	II. REVENUE REQUIREMENTS				
12	Investment Return and Income Taxes	II(A)	4,124,786	Sheet 4a, Line 15(4)	(b)
13	Depreciation Expense	II(B)	63,152	Sheet 8, Line 5	(a)
14	Amortization of Loss on Reacquired Debt	II(C)	413	Sheet 8, Line 6	(a)
15	Investment Tax Credit	II(D)	(476)	Sheet 8, Line 7	(a)
16	Property Tax Expense	II(E)	38,063	Sheet 8, Line 8	(a)
17	Payroll Tax Expense	II(F)	275	Sheet 8, Line 21	(a)
18	Operation & Maintenance Expense	II(G)	32,286	Sheet 8, Line 29	(a)
19	Administrative & General Expense	II(H)	37,629	Sheet 8, Line 40	(b)
20	Support Expenses	II(I)	-		(a)
21	Transmission Related Taxes and Fees	II(J)	8,406	Sheet 8, Line 41	(a)
22	Total Revenue Requirements (Line 11 thru 20)		4,304,534		(b)

Note:
Investment Return and Income Taxes (line 11 above) was calculated based on the Total Investment Base at 11.07% ROE, plus the Localized Post-2003 PTF Transmission Base (lines 1-3-4) at the .67% capped Incremental ROE.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Glenbrook Cables
Sheet 2

Line No.	(A)	(B) Trans. Related Average		(C) Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Transmission Plant							
1	Localized Transmission Plant					2,570,000	Sheet 3, Line 17	(a)
2	Transmission General Plant	102,812,641	Note 4				FF1 page 204 ln. 96, footnote	(a)
3	Less: Convex-related General Plant	15,870,872					Note 1	(a)
4	Subtotal: General Plant, net of Convex (line 2 - 3)	86,941,769		0.0853%	Note 2	74,161		(a)
5	Total (line 1+4)					2,644,161		(a)
6	Localized Transmission Plant Held for Future Use					31,396,972		(a)
	Transmission Accumulated Depreciation							
7	Localized Transmission Accum. Depreciation					334,418	Sheet 9, Line 17(I)	(a)
8	General Plant Accum. Depreciation	26,085,325	Note 4				FF1 page 219 ln. 28, footnote	(a)
9	Less: Convex-related General Plant Acc Depr	3,717,252					Note 1	(a)
10	Subtotal: General Plant A/D, net of Convex (line 8-9)	22,368,074		0.0853%	Note 2	19,080		(a)
11	Total (line 7+10)					353,497		(a)
12	Transmission Accumulated Deferred Taxes					323,209	Sheet 10, Line 32	(a)
13	Unam. Loss on Reacquired Debt (189)	12,599,425		0.0315%	Note 3	3,969	FF1 page 111 ln. 81	(a)
14	Localized Transmission Other Regulatory Assets	3,576,663		0.0853%		3,051	Exhibit No. ES-220, Page 1 of 8, Line 4(D)	(b)
15	Transmission Prepayments (165)	19,487,085	Note 4	0.0853%	Note 2	16,622	FF1 page 110 ln. 57, footnote	(a)
15	Transmission Materials and Supplies	36,123,136		0.0853%	Note 2	30,813	FF1 page 227 ln. 8	(a)
	Cash Working Capital							
16	Localized Operation & Maintenance Expense					32,286	Sheet 8, Line 29	(a)
17	Localized Administrative & General Expense					37,629	Sheet 8, Line 40	(c)
18	Subtotal (line 16+17)					69,915		(c)
19	12.5% allowance					0.125	x 45 / 360	(a)
20	Total current Year End (line 18*19)					8,739		(c)
21	Prior Year End Cash Working Capital					8,739		(d)
22	Average Cash Working Capital [(line 20+21)/2]					8,739		(c)

Note 1: Reflects actual information per Eversource's accounting records.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset
(c) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses
(d) Exhibit No. 226, Schedule 4, Page 13 of 26, Line 21(D)

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Glenbrook Cables
Sheet 4a

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559	Note 2	46.27%	5.36%	Note 2	2.48%		
2	PREFERRED STOCK	$ 116,842,775		2.14%	4.80%		0.10%	0.10%	
3	COMMON EQUITY	$ 2,820,159,065		51.59%	11.07%	Note 1	5.71%	5.71%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399		100.00%			8.29%	5.81%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 8.29% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) / (1 - Federal Income Tax Rate) + Eq. AFUDC of Deprec. Exp.) / Total Inv. Base)) * Federal Income Tax Rate)

Source: Line 4, Col. (5); Sheet 8, Line 7; Sheet 6, Line 1; Sheet 1, Line 10; Federal Corporate Tax Rate

6 = ((5.81% + (((476) + 1,968) / 33,427,621)) * 35.00%)
7 (1 - 35.00%) Federal Corporate Tax Rate

8 = 3.1309%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) / (1 - State Income Tax Rate) + Eq. AFUDC of Deprec. Exp.) / Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)

Source: Line 4, Col. (5); Sheet 8, Line 7; Sheet 6, Line 1; Sheet 1, Line 10; Line 8, Col. (1); Connecticut Corporate Tax Rate

9 = ((5.81% + (((476) + 1,968) / 33,427,621) + 3.1309%) * 9.00%)
10 (1 - 9.00%) Connecticut Corporate Tax Rate

11 = 0.8847%

12 (a)+(b)+(c) **Cost of Capital Rate** = 12.3056%

Line			
13	INVESTMENT BASE	33,427,621	Sheet 1, Line 10
14			
15	x Cost of Capital Rate	12.3056%	Line 12, Col. (1)
16	= Investment Return and Income Taxes	$ 4,113,469	

Total Investment Return and Income Taxes		
@11.07%	$ 4,113,469	Line 16, Col. (1)
@.67%	$ 11,317	Sheet 5a, Line 17
	$ 4,124,786	To Sheet 1a, Line 11

Note 1: ROE per FERC Order in Docket No. ER11-66 dated October 16, 2014.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes:

(1) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Glenbrook Cables

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559	Note 2	46.27%					
2	PREFERRED STOCK	$ 116,842,775		2.14%					
3	COMMON EQUITY	$ 2,820,159,065		51.59%	0.50%	Note 1	0.26%	0.26%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399		100.00%			0.26%	0.26%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.26% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate) Total Inv. Base)) * Federal Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Federal Corporate Tax Rate

6 = ((0.26% + ((0 + 0) / 33,427,621)) * 35.00%)
7 (1 - 35.00%) Federal Corporate Tax Rate

8 = 0.1400%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate) Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Line 8, Col. (1); Connecticut Corporate Tax Rate

9 = ((0.26% + ((0 + 0) / 33,427,621) + 0.1400%) * 9.00%)
10 (1 - 9.00%) Connecticut Corporate Tax Rate

11 = 0.0396%

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.4396%

13 INVESTMENT BASE 33,427,621 Line 16, Col. (4)

14 x Cost of Capital Rate 0.4396% Line 12, Col. (1)

15 = Investment Return and Income Taxes $ 146,948 to Sheet 4a, Line 14(4)

Note 1: CAP on ROE incentives per FERC Order in Docket No. EL11-66 dated March 3, 2015.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.

Notes:

(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-224, Schedule 1, Page 4 of 4, Line 18

(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Glenbrook Cables
Sheet 8

Line No.	(A)	(B) Year End		(C) Localized Trans. Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Depreciation Expense							
1	Transmission Depreciation					59,851	Sheet 9, Line 19	(a)
2	General Depreciation	4,980,574	Note 4				FF1 page 336 ln. 10, footnote	(a)
3	*less:* Convex-related General Plant Depreciation Expense	1,110,693					Note 1	(a)
4	Subtotal: General Plant Depr Exp, net of Convex (line 2-3)	3,869,881		0.0853%	Note 2	3,301		(a)
5	Total (line 1+4)					63,152		(a)
6	Amortization of Loss on Reacquired Debt	1,309,927		0.0315%	Note 3	413	FF1 page 117 ln. 64	(a)
7	Amortization of Investment Tax Credits	1,511,975		0.0315%	Note 3	476	FF1 page 266 ln. 8 (f)	(a)
8	Property Taxes	120,836,131		0.0315%	Note 3	38,063	FF1 page 263 ln. 24i & 25i	(a)
	Payroll Tax Expense							
9	Federal Unemployment	5,226					FF1 page 262 ln. 3i, footnote	(a)
10	FICA	233,351					FF1 page 262 ln. 5i, footnote	(a)
11	Medicare	65,613					FF1 page 262 ln. 9i, footnote	(a)
12	CT Unemployment	16,786					FF1 page 262 ln. 15i, footnote	(a)
13	MA Unemployment	(285)					FF1 page 262 ln. 32i, footnote	(a)
14	MA Universal Health	64					FF1 page 262 ln. 33i, footnote	(a)
15	NH Unemployment	1,754					FF1 page 262.1 ln. 4i, footnote	(a)
16	NJ Unemployment	-					FF1 page 262 footnote	(a)
17	DC Unemployment	11					FF1 page 262.1 ln. 14i, footnote	(a)
18	FL Unemployment	1					FF1 page 262.1 ln. 18i, footnote	(a)
19	MI Unemployment	6					FF1 page 262.1 ln. 22i, footnote	(a)
20	NY Unemployment	-					FF1 page 262.1 ln. 10i, footnote	(a)
21	Total (Line 9 to 20)	322,527	Note 4	0.0853%	Note 2	275		
	Transmission Operation and Maintenance							
22	Operation and Maintenance	77,432,007					FF1 page 321 ln. 112	(a)
23	Transmission of Electricity by Others - #565	21,727,966					FF1 page 321 ln. 96	(a)
24	Load Dispatching - #561	-					FF1 page 321 ln. 84	(a)
25	Account 561.1	3,245,594					FF1 page 321 ln. 85	(a)
26	Account 561.2	5,212,556					FF1 page 321 ln. 86	(a)
27	Account 561.3	2,238,612					FF1 page 321 ln. 87	(a)
28	Account 561.4	7,157,291					FF1 page 321 ln. 88	(a)
29	O&M (line 22 - lines 23 to 28)	37,849,988		0.0853%	Note 2	32,286		(a)
	Transmission-related Administrative and General							
30	Administrative and General	37,202,294	Note 4				FF1 page 320 ln. 197 b, footnote	(a)
31	less: Property Insurance (#924)	763,857	Note 4				FF1 Page 320 ln. 185 b, footnote	(a)
32	less: Regulatory Commission Expenses (#928)	2,749,411	Note 4				FF1 page 320 ln. 189 b, footnote	(a)
33	less: General Advertising Expense (#930.1)	10,766	Note 4				FF1 page 320 ln. 191 b, footnote	(a)
34	Subtotal (line 30 - lines 31 to 33)	33,678,260		0.0853%	Note 2	28,728		(a)
35	plus: Property Insurance	1,413,419		0.0315%	Note 3	445	FF1 page 323 ln. 185	(a)
36	plus: Trans. Regulatory Comm. Exp.	2,749,411		0.0853%	Note 2	2,345	FF1 page 320 ln. 189 b, footnote	(a)
37	plus: Trans. Related General Advertising Expense	10,766		0.0853%	Note 2	9	FF1 page 320 ln. 191 b, footnote	(a)
38	plus: Trans. Related Public Education Expense	-				-	FF1 page 114 ln. 49, footnote	(a)
39	plus: Trans. Merger-Related Costs	7,153,326		0.0853%		6,102	Exhibit No. ES-220, Page 1 of 8, Line 2(D)	(b)
40	Total A&G (sum of lines 34 to 38)	45,005,182				37,629		(b)
41	Transmission Related Taxes and Fees	9,854,673		0.0853%	Note 2	8,406	Note 5	(a)

Note 1: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.
Note 5: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment B.

Notes:

(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 1a

Line No.	(A)	Attachment I Reference Section:	(B)	(C) Source	(D) Notes
	I. INVESTMENT BASE				
1	Transmission Plant	II(A)(1)(a)	3,169,795	Sheet 2, Line 5	(a)
2	Transmission Plant Held for Future Use	II(A)(1)(b)	-	Sheet 2, Line 6	(a)
3	Accumulated Depreciation	II(A)(1)(c)	116,694	Sheet 2, Line 11	(a)
4	Accumulated Deferred Income Taxes	II(A)(1)(d)	265,445	Sheet 2, Line 12	(a)
5	Loss On Reacquired Debt	II(A)(1)(e)	4,750	Sheet 2, Line 13	(a)
6	Other Regulatory Assets	II(A)(1)(f)	3,659	Sheet 2, Line 14	(b)
7	Net Investment (Line 1+2-3-4+5)		2,796,065		(b)
8	Prepayments	II(A)(1)(g)	19,935	Sheet 2, Line 15	(a)
9	Materials & Supplies	II(A)(1)(h)	36,954	Sheet 2, Line 16	(a)
10	Cash Working Capital	II(A)(1)(i)	10,481	Sheet 2, Line 23	(b)
11	Total Investment Base (Line 6+7+8+9)		2,863,435		(b)
	II. REVENUE REQUIREMENTS				
12	Investment Return and Income Taxes	II(A)	369,614	Sheet 4a, Line 15(4)	(b)
13	Depreciation Expense	II(B)	78,802	Sheet 8, Line 5	(a)
14	Amortization of Loss on Reacquired Debt	II(C)	494	Sheet 8, Line 6	(a)
15	Investment Tax Credit	II(D)	(570)	Sheet 8, Line 7	(a)
16	Property Tax Expense	II(E)	45,555	Sheet 8, Line 8	(a)
17	Payroll Tax Expense	II(F)	330	Sheet 8, Line 21	(a)
18	Operation & Maintenance Expense	II(G)	38,721	Sheet 8, Line 29	(a)
19	Administrative & General Expense	II(H)	45,128	Sheet 8, Line 40	(b)
20	Support Expenses	II(I)	-		(a)
21	Transmission Related Taxes and Fees	II(J)	10,081	Sheet 8, Line 41	(a)
22	Total Revenue Requirements (Line 11 thru 20)		588,155		(b)

Note:
Investment Return and Income Taxes (line 11 above) was calculated based on the Total Investment Base at 11.07% ROE, plus the Localized PTF Transmission Base (lines 1-3-4) at the .67% capped Incremental ROE.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 2

Line No.	(A)	(B) Trans. Related Average		(C) Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Transmission Plant							
1	Localized Transmission Plant					3,080,854	Sheet 3, Line 18	(a)
2	Transmission General Plant	102,812,641	Note 4				FF1 page 204 ln. 96, footnote	(a)
3	Less: Convex-related General Plant	15,870,872					Note 1	(a)
4	Subtotal: General Plant, net of Convex (line 2 - 3)	86,941,769		0.1023%	Note 2	88,941		(a)
5	Total (line 1+4)					3,169,795		(a)
6	Localized Transmission Plant Held for Future Use					-		(a)
	Transmission Accumulated Depreciation							
7	Localized Transmission Accum. Depreciation					93,811	Sheet 9, Line 10(I)	(a)
8	General Plant Accum. Depreciation	26,085,325	Note 4				FF1 page 219 ln. 28, footnote	(a)
9	Less: Convex-related General Plant Acc Depr	3,717,252					Note 1	(a)
10	Subtotal: General Plant A/D, net of Convex (line 8-9)	22,368,074		0.1023%	Note 2	22,883		(a)
11	Total (line 7+10)					116,694		(a)
12	Transmission Accumulated Deferred Taxes					265,445	Sheet 10, Line 46	(a)
13	Unam. Loss on Reacquired Debt (189)	12,599,425		0.0377%	Note 3	4,750	FF1 page 111 ln. 81	(a)
14	Localized Transmission Other Regulatory Assets	3,576,663		0.1023%		3,659	Exhibit No. ES-220, Page 1 of 8, Line 4(D)	(b)
15	Transmission Prepayments (165)	19,487,085	Note 4	0.1023%	Note 2	19,935	FF1 page 110 ln. 57, footnote	(a)
16	Transmission Materials and Supplies	36,123,136		0.1023%	Note 2	36,954	FF1 page 227 ln. 8	(a)
	Cash Working Capital							
17	Localized Operation & Maintenance Expense					38,721	Sheet 8, Line 29	(a)
18	Localized Administrative & General Expense					45,128	Sheet 8, Line 40	(c)
19	Subtotal (line 16+17)					83,849		(c)
20	12.5% allowance					0.125	x 45 / 360	(a)
21	Total current Year End (line 18*19)					10,481		(c)
22	Prior Year End Cash Working Capital					10,481		(d)
23	Average Cash Working Capital [(line 20+21)/2]					10,481		(c)

Note 1: Reflects actual information per Eversource's accounting records.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset
(c) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 4a

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559	Note 2	46.27%	5.36%	Note 2	2.48%		
2	PREFERRED STOCK	$ 116,842,775		2.14%	4.80%		0.10%	0.10%	
3	COMMON EQUITY	$ 2,820,159,065		51.59%	11.07%	Note 1	5.71%	5.71%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399		100.00%			8.29%	5.81%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 8.29% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + (((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate)) / Total Inv. Base)) * Federal Income Tax Rate)

Source: Line 4, Col. (5); Sheet 8, Line 7; Sheet 6, Line 1; Sheet 1, Line 10; Federal Corporate Tax Rate

6 = ((5.81% + (((570) + 2,360) / Federal Corporate Tax Rate
7 (1 - 35.00%)) / 2,863,435)) * 35.00%)

8 = 3.1621%

(c) State Income Tax = ((R.O.E. + (((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate)) / Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)

Source: Line 4, Col. (5); Sheet 8, Line 7; Sheet 6, Line 1; Sheet 1, Line 10; Line 8, Col. (1); Connecticut Corporate Tax Rate

9 = ((5.81% + (((570) + 2,360) / 2,863,435) + 3.1621%) * 9.00%)
10 (1 - 9.00%) Connecticut Corporate Tax Rate

11 = 0.8935%

12 (a)+(b)+(c) **Cost of Capital Rate** = 12.3456%

Line			
13	INVESTMENT BASE	2,863,435	Sheet 1, Line 10
14			
15	x Cost of Capital Rate	12.3456%	Line 12, Col. (1)
16	= Investment Return and Income Taxes	$ 353,508	

Total Investment Return and Income Taxes		
@11.07%	$ 353,508	Line 16, Col. (1)
@.67%	$ 16,106	Sheet 5a, Line 17
	$ 369,614	To Sheet 1a, Line 11

Note 1: ROE per FERC Order in Docket No. ER11-66 dated October 16, 2014.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes:

(1) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 5a

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 2,529,279,559	Note 2	46.27%					
2	PREFERRED STOCK	$ 116,842,775		2.14%					
3	COMMON EQUITY	$ 2,820,159,065		51.59%	0.50%	Note 1	0.26%	0.26%	
4	TOTAL INVESTMENT RETURN	$ 5,466,281,399		100.00%			0.26%	0.26%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.26% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate) Total Inv. Base)) * Federal Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Federal Corporate Tax Rate

6 = ((0.26% + ((0 + 0) / 2,863,435)) * 35.00%)
7 (1 - 35.00%) Federal Corporate Tax Rate

8 = 0.1400%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate) Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Line 8, Col. (1); Connecticut Corporate Tax Rate

9 = ((0.26% + ((0 + 0) / 2,863,435) + 0.1400%) * 9.00%)
10 (1 - 9.00%) Connecticut Corporate Tax Rate

11 = 0.0396%

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.4396%

13 INVESTMENT BASE 2,863,435 Line 16, Col. (4)

14 x Cost of Capital Rate 0.4396% Line 12, Col. (1)

15 = Investment Return and Income Taxes $ 12,588 to Sheet 4a, Line 14(4)

Note 1: CAP on ROE incentives per FERC Order in Docket No. EL11-66 dated March 3, 2015.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.

Notes:

(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-224, Schedule 1, Page 4 of 4, Line 18
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

The Connecticut Light and Power Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 8

Line No.	(A)	(B) Year End		(C) Localized Trans. Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Depreciation Expense							
1	Transmission Depreciation					74,843	Sheet 9, Line 12	(a)
2	General Depreciation	4,980,574	Note 4				FF1 page 336 ln. 10, footnote	(a)
3	*less:* Convex-related General Plant Depreciation Expense	1,110,693					Note 1	(a)
4	Subtotal: General Plant Depr Exp, net of Convex (line 2-3)	3,869,881		0.1023%	Note 2	3,959		(a)
5	Total (line 1+4)					78,802		(a)
6	Amortization of Loss on Reacquired Debt	1,309,927		0.0377%	Note 3	494	FF1 page 117 ln. 64	(a)
7	Amortization of Investment Tax Credits	1,511,975		0.0377%	Note 3	570	FF1 page 266 ln. 8 (f)	(a)
8	Property Taxes	120,836,131		0.0377%	Note 3	45,555	FF1 page 263 ln. 24i & 25i	(a)
	Payroll Tax Expense							
9	Federal Unemployment	5,226					FF1 page 262 ln. 3i, footnote	(a)
10	FICA	233,351					FF1 page 262 ln. 5i, footnote	(a)
11	Medicare	65,613					FF1 page 262 ln. 9i, footnote	(a)
12	CT Unemployment	16,786					FF1 page 262 ln. 15i, footnote	(a)
13	MA Unemployment	(285)					FF1 page 262 ln. 32i, footnote	(a)
14	MA Universal Health	64					FF1 page 262 ln. 33i, footnote	(a)
15	NH Unemployment	1,754					FF1 page 262.1 ln. 4i, footnote	(a)
16	NJ Unemployment	-					FF1 page 262 footnote	(a)
17	DC Unemployment	11					FF1 page 262.1 ln. 14i, footnote	(a)
18	FL Unemployment	1					FF1 page 262.1 ln. 18i, footnote	(a)
19	MI Unemployment	6					FF1 page 262.1 ln. 22i, footnote	(a)
20	NY Unemployment	-					FF1 page 262.1 ln. 10i, footnote	(a)
21	Total (Line 9 to 20)	322,527	Note 4	0.1023%	Note 2	330		
	Transmission Operation and Maintenance							
22	Operation and Maintenance	77,432,007					FF1 page 321 ln. 112	(a)
23	Transmission of Electricity by Others - #565	21,727,966					FF1 page 321 ln. 96	(a)
24	Load Dispatching - #561	-					FF1 page 321 ln. 84	(a)
25	Account 561.1	3,245,594					FF1 page 321 ln. 85	(a)
26	Account 561.2	5,212,556					FF1 page 321 ln. 86	(a)
27	Account 561.3	2,238,612					FF1 page 321 ln. 87	(a)
28	Account 561.4	7,157,291					FF1 page 321 ln. 88	(a)
29	O&M (line 22 - lines 23 to 28)	37,849,988		0.1023%	Note 2	38,721		(a)
	Transmission-related Administrative and General							
30	Administrative and General	37,202,294	Note 4				FF1 page 320 ln. 197 b, footnote	(a)
31	less: Property Insurance (#924)	763,857	Note 4				FF1 Page 320 ln. 185 b, footnote	(a)
32	less: Regulatory Commission Expenses (#928)	2,749,411	Note 4				FF1 page 320 ln. 189 b, footnote	(a)
33	less: General Advertising Expense (#930.1)	10,766	Note 4				FF1 page 320 ln. 191 b, footnote	(a)
34	Subtotal (line 30 - lines 31 to 33)	33,678,260		0.1023%	Note 2	34,453		(a)
35	plus: Property Insurance	1,413,419		0.0377%	Note 3	533	FF1 page 323 ln. 185	(a)
36	plus: Trans. Regulatory Comm. Exp.	2,749,411		0.1023%	Note 2	2,813	FF1 page 320 ln. 189 b, footnote	(a)
37	plus: Trans. Related General Advertising Expense	10,766		0.1023%	Note 2	11	FF1 page 320 ln. 191 b, footnote	(a)
38	plus: Trans. Related Public Education Expense	-				-	FF1 page 114 ln. 49, footnote	(a)
39	plus: Trans. Merger-Related Costs	7,153,326		0.1023%		7,318	Exhibit No. ES-220, Page 1 of 8, Line 2(D)	(b)
40	Total A&G (sum of lines 34 to 38)	45,005,182				45,128		(b)
41	Transmission Related Taxes and Fees	9,854,673		0.1023%	Note 2	10,081	Note 5	(a)

Note 1: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.
Note 5: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment B.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Western Massachusetts Electric Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 1a

Line No.	(A)	Attachment I Reference Section:	(B)	(C) Source	(D) Notes
	I. INVESTMENT BASE				
1	Transmission Plant	II(A)(1)(a)	7,316,798	Sheet 2, Line 5	(a)
2	Transmission Plant Held for Future Use	II(A)(1)(b)	-	Sheet 2, Line 6	(a)
3	Accumulated Depreciation	II(A)(1)(c)	290,421	Sheet 2, Line 11	(a)
4	Accumulated Deferred Income Taxes	II(A)(1)(d)	603,776	Sheet 2, Line 12	(a)
5	Loss On Reacquired Debt	II(A)(1)(e)	2,313	Sheet 2, Line 13	(a)
6	Other Regulatory Assets	II(A)(1)(f)	8,318	Sheet 2, Line 14	(b)
7	Net Investment (Line 1+2-3-4+5)		6,433,232		(b)
8	Prepayments	II(A)(1)(g)	5,502	Sheet 2, Line 15	(a)
9	Materials & Supplies	II(A)(1)(h)	26,259	Sheet 2, Line 16	(a)
10	Cash Working Capital	II(A)(1)(i)	17,521	Sheet 2, Line 23	(b)
11	Total Investment Base (Line 6+7+8+9)		6,482,514		(b)
	II. REVENUE REQUIREMENTS				
12	Investment Return and Income Taxes	II(A)	781,490	Sheet 4a, Line 15(4)	(b)
13	Depreciation Expense	II(B)	184,929	Sheet 8, Line 5	(a)
14	Amortization of Loss on Reacquired Debt	II(C)	323	Sheet 8, Line 6	(a)
15	Investment Tax Credit	II(D)	(154)	Sheet 8, Line 7	(a)
16	Property Tax Expense	II(E)	144,952	Sheet 8, Line 8	(a)
17	Payroll Tax Expense	II(F)	157	Sheet 8, Line 21	(a)
18	Operation & Maintenance Expense	II(G)	54,519	Sheet 8, Line 29	(a)
19	Administrative & General Expense	II(H)	85,648	Sheet 8, Line 39	(b)
20	Support Expenses	II(I)	-		(a)
21	Transmission Related Taxes and Fees	II(J)	177	Sheet 8, Line 40	(a)
22	Total Revenue Requirements (Line 11 thru 20)		1,252,041		(b)

Note:
Investment Return and Income Taxes (line 11 above) was calculated based on the Total Investment Base at 11.07% ROE, plus the Localized PTF Transmission Base (lines 1-3-4) at the .67% capped Incremental ROE.

Notes:

(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247

(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses and the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset

Western Massachusetts Electric Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 2

Line No.	(A)	(B) Trans. Related Average		(C) Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Transmission Plant							
1	Localized Transmission Plant					7,159,714	Sheet 3, Line 33	(a)
2	Transmission General Plant	18,348,753	Note 4	0.8561%	Note 2	157,084	FF1 page 204 ln. 96, footnote	(a)
3	Total (line 1+2)					7,316,798		(a)
4	Localized Transmission Plant Held for Future Use					-		(a)
	Transmission Accumulated Depreciation							
5	Localized Transmission Accum. Depreciation					256,419	Sheet 9, Line 27(I)	(a)
6	General Plant Accum.Depreciation	3,971,742	Note 4	0.8561%	Note 2	34,002	FF1 page 219 ln. 28, footnote	(a)
7	Total (line 5+6)					290,421		(a)
8								
9	Transmission Accumulated Deferred Taxes					603,776	Sheet 10, Line 46	(a)
10	Unam. Loss on Reacquired Debt (189)	533,928		0.4332%	Note 3	2,313	FF1 page 111 ln. 81	(a)
11	Localized Transmission Other Regulatory Assets	971,605		0.8561%		8,318	Exhibit No. ES-220, Page 4 of 8, Line 4(D)	(b)
12	Transmission Prepayments (165)	642,737	Note 4	0.8561%	Note 2	5,502	FF1 page 110 ln. 57, footnote	(a)
13	Transmission Materials and Supplies	3,067,304		0.8561%	Note 2	26,259	FF1 page 227 ln. 8	(a)
	Cash Working Capital							
14	Localized Operation & Maintenance Expense					54,519	Sheet 8, Line 28	(a)
15	Localized Administrative & General Expense					85,648	Sheet 8, Line 39	(c)
16	Subtotal (line 13+14)					140,167		(c)
17	12.5% allowance					0.125	x 45 / 360	(a)
18	Total current Year End (line 15*16)					17,521		(c)
19	Prior Year End Cash Working Capital					17,521		(d)
20	Average Cash Working Capital [(line 17+18)/2]					17,521		(c)

Note 1: Reflects actual information per Eversource's accounting records.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the Unamortized Balance of Merger-Related Transmission Costs in the Other Regulatory Asset
(c) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Western Massachusetts Electric Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 4a

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 568,072,183	Note 2	49.54%	4.31%	Note 2	2.14%		
2	PREFERRED STOCK	$ -		0.00%	0.00%		0.00%	0.00%	
3	COMMON EQUITY	$ 578,634,319		50.46%	11.07%	Note 1	5.59%	5.59%	
4	TOTAL INVESTMENT RETURN	$ 1,146,706,502		100.00%			7.73%	5.59%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 7.73% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - Federal Income Tax Rate) Total Inv. Base)) * Federal Income Tax Rate)

Source: Line 4, Col. (5); Sheet 8, Line 7; Sheet 6, Line 1; Sheet 1, Line 10; Federal Corporate Tax Rate

6 = ((5.59% + (((154) + 1,593) / 6,482,514)) * 35.00%)
7 (1 - 35.00%)
Federal Corporate Tax Rate

8 = 3.0220%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / (1 - State Income Tax Rate) Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)

Source: Line 4, Col. (5); Sheet 8, Line 7; Sheet 6, Line 1; Sheet 1, Line 10; Line 8, Col. (1); Massachusetts Corporate Tax Rate

9 = ((5.59% + (((154) + 1,593) / 6,482,514) + 3.0220%) * 8.00%)
10 (1 - 8.00%)
Massachusetts Corporate Tax Rate

11 = 0.7508%

12 (a)+(b)+(c) **Cost of Capital Rate** = 11.5028%

Line			
13	INVESTMENT BASE	6,482,514	Sheet 1, Line 10
14			
15	x Cost of Capital Rate	11.5028%	Line 12, Col. (1)
16	= Investment Return and Income Taxes	$ 745,671	

Total Investment Return and Income Taxes			
@11.07%	$	745,671	Line 16, Col. (1)
@.67%	$	35,819	Sheet 5, Line 17
	$	781,490	To Sheet 1a, Line 11

Note 1: ROE per FERC Order in Docket No. ER04-157 dated March 24, 2008.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment H.

Notes:

(1) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Western Massachusetts Electric Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project

Line No.		(1) 2014 AVERAGE CAPITALIZATION		(2) CAPITALIZATION RATIOS	(3) COST OF CAPITAL		(4) = (3) x (2) WEIGHTED COST OF CAPITAL	(5) = (4) Equity only EQUITY PORTION	(6)
1	LONG-TERM DEBT	$ 568,072,183	Note 2	49.54%					
2	PREFERRED STOCK	$ -		0.00%					
3	COMMON EQUITY	$ 578,634,319		50.46%	0.50%	Note 1	0.25%	0.25%	
4	TOTAL INVESTMENT RETURN	$ 1,146,706,502		100.00%			0.25%	0.25%	

Cost of Capital Rate=

5 (a) Weighted Cost of Capital = 0.25% Line 4, Col. (4)

(b) Federal Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / Total Inv. Base)) * Federal Income Tax Rate)
(1 - Federal Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Federal Corporate Tax Rate
6 = ((0.25% + ((0 + 0) / 6,482,514)) * 35.00%)
7 (1 - 35.00%)
Federal Corporate Tax Rate

8 = 0.1346%

(c) State Income Tax = ((R.O.E. + ((Total Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.) / Total Inv. Base) + Federal Income Tax) * State Income Tax Rate)
(1 - State Income Tax Rate)

Source: Line 4, Col. (5); Line 16, Col. (4); Line 8, Col. (1); Massachusetts Corporate Tax Rate
9 = ((0.25% + ((0 + 0) / 6,482,514) + 0.1346%) * 8.00%)
10 (1 - 8.00%)
Massachusetts Corporate Tax Rate

11 = 0.0334%

12 (a)+(b)+(c) **Cost of Capital Rate** = 0.4180%

13	INVESTMENT BASE	6,482,514	Line 16, Col. (4)
14	x Cost of Capital Rate	0.4180%	Line 12, Col. (1)
15	= Investment Return and Income Taxes	$ 27,097	to Sheet 4a, Line 14(4)

Note 1: CAP on ROE incentives per FERC Order in Docket No. EL11-66 dated March 3, 2015.
Note 2: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.

Notes:

(1) This worksheet was created for this filing in order to break out the incentives associated with revenue credits in Exhibit No. ES-224, Schedule 1, Page 4 of 4, Line 18
(2) The balance in "Total Inv. Base" is revised under the Changed Rates to reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Western Massachusetts Electric Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Estimated Category B Revenue Requirements
Calculated under the Changed Rates in Attachment ES-I (Formerly Attachment NU-I)
For Costs in 2014
Greater Springfield Reliability Project
Sheet 8

Line No.	(A)	(B) Year End		(C) Localized Trans. Allocation Factor		(D) Allocated to Localized	(E) Source	(F) Notes
	Depreciation Expense							
1	Transmission Depreciation					178,169	Sheet 9, Line 29	(a)
2	General Depreciation	789,658	Note 4	0.8561%	Note 2	6,760	FF1 page 336 ln. 10, footnote	(a)
3	Total (line 1+4)					184,929		(a)
4								(a)
								(a)
5	Amortization of Loss on Reacquired Debt	74,501		0.4332%	Note 3	323	FF1 pg 117 ln. 64	
								(a)
6	Amortization of Investment Tax Credits	35,604		0.4332%	Note 3	154	FF1 page 266 ln. 8(f), footnote	
								(a)
7	Property Taxes	33,460,690		0.4332%	Note 3	144,952	FF1 page 263 ln. 31i & 32i	
								(a)
	Payroll Tax Expense							
8	Federal Unemployment	283					FF1 page 262 ln. 3i, footnote	
9	FICA	13,202					FF1 page 262 ln. 5i, footnote	(a)
10	Medicare	3,757					FF1 page 262 ln. 9i, footnote	(a)
11	CT Unemployment	852					FF1 page 262 ln. 13i, footnote	(a)
12	MA Unemployment	69					FF1 page 262 ln. 22i, footnote	(a)
13	MA Universal Health	19					FF1 page 262 ln. 27i, footnote	(a)
14	NH Unemployment	108					FF1 page 262 ln. 37i, footnote	(a)
15	NJ Unemployment	-					FF1 page 262, footnote	(a)
16	DC Unemployment	1					FF1 page 262.1 ln. 6i, footnote	(a)
17	FL Unemployment	-					FF1 page 262, footnote	(a)
18	MI Unemployment	-					FF1 page 262, footnote	(a)
19	NY Unemployment	-					FF1 page 262, footnote	(a)
20	Total (Line 9 to 20)	18,291	Note 4	0.8561%	Note 2	157		(a)
	Transmission Operation and Maintenance							
21	Operation and Maintenance	20,725,279					FF1 page 321 ln. 112	
22	Transmission of Electricity by Others - #565	13,174,678					FF1 page 321 ln. 96	(a)
23	Load Dispatching - #561	-					FF1 page 321 ln. 84	(a)
24	Account 561.1	12,368					FF1 page 321 ln. 85	(a)
25	Account 561.2	50,569					FF1 page 321 ln. 86	(a)
26	Account 561.3	13,262					FF1 page 321 ln. 87	(a)
27	Account 561.4	1,106,108					FF1 page 321 ln. 88	(a)
28	O&M (line 22 - lines 23 to 28)	6,368,294		0.8561%	Note 2	54,519		(a)
								(a)
	Transmission-related Administrative and General							
29	Administrative and General	8,041,502	Note 4				FF1 page 320 ln. 197, footnote	(a)
30	less: Property Insurance (#924)	106,141	Note 4				FF1 Page 320 ln. 185 b, footnote	(a)
31	less: Regulatory Commission Expenses (#928)	563,123	Note 4				FF1 page 320 ln. 189 b, footnote	(a)
32	less: General Advertising Expense (#930.1)	2,857	Note 4				FF1 page 320 ln. 191 b, footnote	(a)
33	Subtotal (line 30 - lines 31 to 33)	7,369,381		0.8561%	Note 2	63,089		(a)
34	plus: Property Insurance	248,747		0.4332%	Note 3	1,078	FF1 page 323 ln. 185	(a)
35	plus: Trans. Regulatory Comm. Exp.	563,123		0.8561%	Note 2	4,821	FF1 page 320 ln. 189 b, footnote	(a)
36	plus: Trans. Related General Advertising Expense	2,857		0.8561%	Note 2	24	FF1 page 320 ln. 191 b, footnote	(a)
37	plus: Trans. Related Public Education Expense	-				-	FF1 page 114 ln. 49, footnote	(a)
38	plus: Trans. Merger-Related Costs	1,943,209		0.8561%		16,636	Exhibit No. ES-220, Page 4 of 8, Line 2(D)	(b)
39	Total A&G (sum of lines 34 to 38)	10,127,317				85,648	Exhibit No. ES-220, Page 1 of 8, Line 2	(b)
40	Transmission Related Taxes and Fees	20,627		0.8561%	Note 2	177	Note 5	
								(a)

Note 1: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2.
Note 2: Sheet 7, Line 3
Note 3: Sheet 7, Line 6
Note 4: Item is specifically Transmission related and reflected in the FERC Form No. 1 or associated footnotes. Therefore, the Wages & Salaries Allocation Factor is not used.
Note 5: Support filed July 31, 2015 in the PTO AC Informational Filing in RT04-2 - Attachment B.

Notes:
(a) Source of information is the NU Regulatory Oversight Filing submitted to State Regulators on July 31, 2015 pursuant to FERC Docket No. ER03-1247
(b) Proposed revisions reflect the addition of Transmission Merger-Related Costs to Administrative and General Expenses

Exhibit No. ES-300

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Eversource Energy Service Company	**)**	**Docket No.**	**ER16-___-000**
Northeast Utilities Service Company	**)**	**Docket No.**	**ER03-1247-000**
ISO New England Inc. , *et al.*	**)**	**Docket Nos.**	**RT04-2-000**
	)		**ER04-116-000**
Bangor Hydro-Electric Company, *et al.*	**)**	**Docket No.**	**ER04-157-000**
NSTAR Electric Company	**)**	**Docket No.**	**EC06-126-000**
NSTAR Electric Company	**)**	**Docket No.**	**EL07-71-000**
NSTAR Electric Company	**)**	**Docket No.**	**ER07-549-000**
NSTAR, *et al.* and Northeast Utilities, *et al.*	**)**	**Docket No.**	**EC11-35-000**

PREPARED DIRECT TESTIMONY OF

MICHAEL P. SYNAN

ON BEHALF OF EVERSOURCE ENERGY SERVICE COMPANY

Exhibit No. ES-300

EXHIBIT TO DIRECT TESTIMONY OF
MICHAEL P. SYNAN

Exhibit No.	Description
ES-301	Benefits Administration Savings Exhibit

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Eversource Energy Service Company	)	**Docket No.**	**ER16-___-000**
Northeast Utilities Service Company	)	**Docket No.**	**ER03-1247-000**
ISO New England Inc. , *et al.*	)	**Docket Nos.**	**RT04-2-000**
	)		**ER04-116-000**
Bangor Hydro-Electric Company, *et al.*	)	**Docket No.**	**ER04-157-000**
NSTAR Electric Company	)	**Docket No.**	**EC06-126-000**
NSTAR Electric Company	)	**Docket No.**	**EL07-71-000**
NSTAR Electric Company	)	**Docket No.**	**ER07-549-000**
NSTAR, *et al.* and Northeast Utilities, *et al.*	)	**Docket No.**	**EC11-35-000**

PREPARED DIRECT TESTIMONY OF
MICHAEL P. SYNAN
ON BEHALF OF EVERSOURCE ENERGY SERVICE COMPANY

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A1. My name is Michael P. Synan and my business address is 1 NSTAR Way, Westwood MA 02090.

Q2. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A2. I am employed by Eversource Energy Service Company ("Eversource Service") as the Director of Benefits Strategy.

Q3. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A3. I have a Bachelor of Arts degree from Merrimack College in Business Administration – Accounting, and a Master's in Business Administration from Nichols College. Prior to my current position as Director, Benefits Strategy, I was employed by Northeast Utilities Service Company (now Eversource Service) from December 2014 to November 2015 as the Manager of Total Rewards, from September 2012-January 2014 as the Manager of Employee Benefits – Retirement Income, Participant Services and Human Resource Finance for Northeast Utilities' subsidiaries. Prior to the merger between NU and NSTAR,[1] I was employed by NSTAR Electric & Gas Corp. as Manager, Employee Benefits and Human Resource Finance for NSTAR's subsidiaries.

Q4. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A4. The purpose of my testimony is to describe the changes that occurred to various benefits administration programs following the merger between NU and NSTAR. I will show that the merger created a unique opportunity for Eversource[2] to implement a variety of modifications to employee benefit programs, leading to

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[1] "Northeast Utilities" and "NSTAR" refer to the pre-merger holding companies.

[2] "Eversource" or "Eversource Energy" refer to the current merged company and all of its operating utility subsidiaries (The Connecticut Light and Power Company ("CL&P"), Public Service Company of New Hampshire ("PSNH"), Western Massachusetts Electric Company ("WMECO"), Yankee Gas Services Company ("Yankee Gas"), NSTAR Electric Company ("NSTAR Electric") and NSTAR Gas Company ("NSTAR Gas")). "Eversource Companies" refers to NSTAR Electric, CL&P, WMECO and PSNH.

significant savings while still providing industry-competitive benefit programs for employees and their dependents.

Q5. ARE YOU SPONSORING ANY EXHIBITS?

A5. Yes. I am sponsoring Exhibit No. ES-301, which provides support for the savings figures I discuss in my testimony. It also provides greater detail on the mechanics of how Eversource Service calculated the savings figures I discuss in my testimony below.

II. OVERVIEW OF BENEFITS ADMINISTRATION AT EVERSOURCE

Q6. PLEASE PROVIDE AN OVERVIEW OF BENEFITS ADMINISTRATION AT EVERSOURCE.

A6. Competitive and comprehensive employee benefits are an essential part of the total compensation package at Eversource, which seeks to reward employees for providing safe, reliable and cost-effective service to its customers. Eversource's benefits program offer a number of elements consistent with the benefits offered by most major employers both within the electric utility industry and outside of it. Eversource provides comprehensive medical, dental, vision and prescription drug benefits to employees and their eligible dependents. In addition, Eversource provides survivor benefits for the financial security of employees and their families, as well as illness and disability plans to provide income replacement for employees and their families when needed. Finally, Eversource sponsors retirement income and retirement health programs for the future health and security of its employees.

Q7. WHAT BENEFITS CHANGES WERE IMPLEMENTED FOLLOWING THE MERGER?

A7. The merger presented Eversource with a unique opportunity to create a standard platform of active health and welfare plan designs; leverage the scale of the merged company to market key health and welfare plans; and consolidate vendors for medical, prescription drug, dental, vision, life insurance and employee assistance programs through this market process. Once the merger was finalized in 2012, Eversource proactively undertook the following steps to realize the unique integration opportunity that the merger afforded. First, Eversource engaged a benefits consultant, Strategic Benefit Advisors, to support the integration effort and evaluate appropriate steps for the merged entity to take moving forward.

Next, Eversource, with the assistance of Strategic Benefit Advisors, compared Legacy NU and Legacy NSTAR[3] programs with those of other utilities as well as those utilized by companies in other industries. Based on this review, Eversource designed a standard platform of active health and welfare plan designs to implement across the newly merged entity. Eversource was able to undertake this comprehensive review due to the integration of Legacy NU's and Legacy NSTAR's benefit packages and the need to provide a consolidated set of options for employees from both Legacy NU and Legacy NSTAR.

[3] "Legacy NU" refers to Northeast Utilities and all of its subsidiaries prior to the merger. "Legacy NSTAR" refers to NSTAR and all of its subsidiaries prior to the merger.

After selecting this standardized platform, Eversource solicited proposals from insurers and third party administrators using a request-for-proposal process; vendors were selected based on administrative capabilities, provider networks and cost. Through this process, Eversource was able to consolidate vendors for medical, prescription drug, dental, vision, life insurance and employee assistance programs. As a result of this consolidation, Eversource now offers three standard health plans: the PPO-100, PPO-90, and the Saver plan, with different payroll contribution and benefit designs to address the diverse needs of employees and their dependents. Eversource also now has a comprehensive prescription drug program that includes utilization management and step therapy programs, among other cost saving features. Finally, Eversource offers two standardized dental plans with payroll contributions reflective of the cost of the plan, and one standard vision plan.

With respect to retirees, following the merger Eversource was able to take advantage of the larger population of early (pre-65) retirees of the newly merged organization and combine the risk pools. Prior to the merger, Legacy NSTAR early retirees had been pooled with active employees for purposes of obtaining coverage from insurers; under this design the monthly contributions paid by retirees were advantaged by the younger, healthier active employee population. Following the merger, the Legacy NSTAR pre-65 risk pool was combined with the already independent risk pool of pre-65 retirees at Legacy NU and retiree rates were adjusted to reflect more age and risk appropriate rates. Simultaneous to this adjustment in risk pooling, Eversource made changes to the health plan designs offered to retirees by transitioning this population to the same new plan design options offered to active employees following the merger. These new plan designs shift more of the cost away from fixed monthly premiums, which are shared between the retiree and Eversource, over to variable out-of-pocket costs paid primarily by the retiree seeking service. The result of all of these changes was a reduction in Eversource expenses.

Eversource was also able to make significant changes to the benefit plans for post-65 retirees. As part of the standardization efforts, Eversource was uniquely positioned to move the prescription drug coverage for retirees from a fully self-administered arrangement and participation in the Retiree Drug Subsidy (“RDS”) Program to an employer sponsored group drug plan under Medicare Part D called an “Employer Group Waiver Plan” (“EGWP”). Under an EGWP, rather than offer individually sponsored prescription drug coverage, plan sponsors offer a Medicare Part D plan to retirees through a pharmacy benefit manager or insurer that contracts directly with the Centers for Medicare & Medicaid Services (CMS). A plan sponsor (such as Eversource) wraps a supplemental plan around the Part D plan to close the gaps in Part D coverage.

Eversource’s EGWP plan was implemented at the start of the 2013 plan year. The timing of the merger and the subsequent marketing and standardization efforts implemented as a result of the merger enabled Eversource to become an early adopter of this approach; absent the merger, both NSTAR and Northeast Utilities likely would have continued to rely on the RDS Program consistent with many other corporations. The EGWP subsidies have significantly reduced costs for Eversource due to offsetting payments received from Medicare Part D, low income subsidies, pharmacy manufacturer reimbursements and catastrophic reinsurance payments. All of these changes to the retiree health plan led to significant savings for Eversource, and as a result, to ratepayers through reduced PBOP expenses as discussed below.

These vendor changes were implemented effective January 1, 2013 for all employees and retirees. Plan design changes were implemented for all non-represented employees effective January 1, 2013 as well.[4]

III. SAVINGS CALCULATION

Q8. HOW WAS THE NEWLY MERGED ENTITY ABLE TO GENERATE SAVINGS?

A8. Eversource has been able to realize significant savings in the area of benefits administration for both active employees and retirees. Savings were achieved through a combination of the benefits initiatives discussed previously and the substantially increased size of the merged entity, which resulted in greater buying power that allowed the merged entity to obtain more favorable terms from benefit

[4] As any change to benefits for represented employees is subject to mandatory collective bargaining, the changes could not be implemented January 1, 2013 for represented employees. However, it should be noted that Eversource successfully negotiated these plan design changes for its largest union effective 2013 and currently all represented employees utilize the same standardized plans offered to non-represented employees.

carriers. Additionally, the significant increase in size of the merged entity led to a more diverse and broader risk pool. Finally, the standardization of the plans described above led to significant decreases in the administrative expenses Eversource incurred as a result of plan administration.

Q9. HOW DID EVERSOURCE CALCULATE THESE SAVINGS AND WHAT ARE THEY?

A9. To calculate these savings, Eversource examined two primary categories; savings from active health care expense and savings from retiree health care expense. Eversource then utilized two methodologies to analyze those categories of expense. As described below, this is appropriate due to the nature of the savings realized and how expenses for active employees differ from expenses for retirees. For active employee health expense, Eversource compared its 2012 active health expense to its 2013 active health expense. As shown on Page 3 of Exhibit No. ES-301, the 2012 enterprise-wide active health expense for Eversource was $117.3 million. In 2013, active health expense for Eversource enterprise-wide was $109.8 million, a reduction of $7.5 million. A portion of this savings is attributable to the employee reductions discussed in Ms. Vaughan's testimony, so Eversource calculated and removed this amount to avoid double counting the savings between the two categories. To calculate this amount, Eversource subtracted the reductions for 2012 benefit savings in the labor savings calculation from the reductions for 2013 benefit savings in the labor savings calculation.[5] The mechanics of this calculation are shown on Page 4 of Exhibit No. ES-301, which indicate that Eversource reduced its active savings figure by $3.0 million. In total, then, Eversource realized $4.5 million in enterprise-wide savings for active health expenses in 2013 alone.

For savings to retiree health expenses, Eversource relied upon projected reductions calculated by its independent retiree health plan actuaries, Mercer and Towers Watson. Both companies projected the reduction in retiree health expense associated with the changes made to the retiree health plans as discussed above. To accomplish this, both Mercer and Towers Watson projected the cost Eversource would be required to pay for Post-Retirement Benefits other than Pensions ("PBOP") expense in 2013 on an enterprise-wide basis without the changes brought about by the merger as compared to what Eversource would have to pay with the changes brought about by the merger.

In a given year, Eversource must utilize a PBOP expense to ensure that it has funds in a specifically designated account equal to its accumulated postretirement benefit obligation ("APBO"). APBO is the actuarial present value of the post-retirement benefits (other than pensions) that an employer, such as Eversource, has incurred on a given date due to employee service as of that particular date. The

[5] Put another way, examining the numbers on Page 4 of Exhibit No. ES-301, Eversource's Active Health expense would have been $1.2 million higher but-for the employee reductions in 2012, and would have been $4.2 million higher but-for employee reductions in 2013. This would mean active employee expense would have been $118.5 million in 2012 and $114.0 million in 2013. The difference between these two numbers is the same $4.5 million figure cited above.

calculation of APBO is prepared by independent actuaries, and varies based on a number of different factors: the demographics of an employee population, the nature of the post-retirement benefits offered to employees, the expected return of assets already in the PBOP account, the discount rate, and others. Eversource relies on these actuaries to evaluate the impact of each of the various factors, including plan design changes, on Eversource's APBO. In a given year, different factors may have a different impact on APBO: if expected return on assets decreases then APBO may need to increase (as the future value of a present dollar received through the PBOP expense decreases), while at the same time if Eversource utilizes new vendors with different cost structures APBO may decrease. Towers Watson and Mercer considered each of the various factors influencing projected APBO in 2013 and determined the increase or decrease (and associated impact on PBOP expense) of each factor.

Their calculations showed that the Pre-65 methodology changes described above accounted for an estimated $12.5 million in savings to PBOP expense in 2013, while the switch to the Medicare Part D Employer Group Waiver Plan accounted for an estimated $10.2 million in savings. Towers Watson and Mercer calculated savings to PBOP expense based on other factors as well, such as favorable return on assets, but as those savings are not related to the merger and did not come about due to the merger they are not included here. In total, then, changes to employee benefits for retirees accounted for an estimated $22.7 million in savings for 2013 alone. Put another way, but-for the changes Eversource made to its retiree health plans following the merger, the actuaries estimated that Eversource would have needed to pay $22.7 million more in PBOP expenses in order to ensure that Eversource had sufficient cash to cover its 2013 APBO.[6] In sum, on an enterprise-wide basis Eversource realized an estimated $27.2 million in merger-related savings within the benefits category for 2013.

This total savings figure includes both savings to O&M expense accounts as well as savings in capitalized accounts. As shown on Page 1 of Exhibit No. ES-301, Eversource only included the expense portion of its savings in 2013 (both the O&M expense and expense portion of capitalized savings) as those are the savings which customers realize in a given year. Given this reduction, the final 2013 savings number on a company-wide basis was $19.3 million.

To calculate savings in 2014 and the portion of 2015 covered in this filing, Eversource assumed that the savings realized in 2013 would continue to be realized in later years. The significant changes described above set a new baseline for Eversource's benefits expenses moving forward, and the meaningful reductions made in 2013 continued in both 2014 and 2015, and will continue into the future.

In developing this calculation, Eversource made the conservative assumption that the savings realized in 2013 were only increased by an inflationary factor

[6] As PBOP expenses are recoverable in the Eversource Companies' electric rates at both the state and federal level, a reduction in PBOP expense to Eversource is in reality a reduction in expense to the Eversource Companies' ratepayers.

specifically relevant to benefit costs in subsequent years.[7] This is a conservative assumption because as described above, since 2013, significant changes have occurred to employee benefits packages for represented employees, all of whom now utilize the same standardized plans offered to non-represented employees. This shift represents even more savings to the Eversource Companies' ratepayers, but again to present a conservative estimate Eversource merely utilized the 2013 savings numbers escalated by a small inflationary factor yearly. An audit of CL&P conducted by a management consulting firm confirmed the significant savings realized in the area of Benefits Administration.[8]

Q10. WHAT WAS EVERSOURCE'S TOTAL SAVINGS IN THIS CATEGORY?

A10. Using this factor, Eversource realized $21.5 million in total savings for 2014 and $16.7 million in total savings for the portion of 2015 covered in this analysis. This amount, added to the enterprise-wide savings of $19.3 million discussed above for 2013, indicates that total savings in the Benefits category on an enterprise-wide basis is equal to $57.5 million. Ms. Vaughan's testimony addresses how this enterprise-wide total was allocated to the transmission function. See Exhibit No. ES-100, Section IV. D.

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[7] The source of the inflation rate is the Employment Cost Index Report, Table A, Private Industry, Benefits, 12-month, not seasonally adjusted value obtained from the Bureau of Labor Statistics at www.bls.gov.

[8] *See* Exhibit No. ES-121 at 188 ("The 2012 merger of NSTAR and NU offered the opportunity for a number of cost savings. The most significant of these was the consolidation of the two company's employee benefits programs.").

Q11. DOES THIS CONCLUDE YOUR TESTIMONY?

A11. Yes.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Eversource Energy Service Company) **Docket No. ER16-___-000**

AFFIDAVIT OF MICHAEL P. SYNAN

Michael P. Synan, being first duly sworn, deposes and says that he is the Michael P. Synan referred to in the foregoing testimony, that he has read such testimony and is familiar with the contents thereof, and that the answers therein are true and correct to the best of his knowledge, information, and belief.

Michael P Synan
Michael P. Synan

Subscribed and sworn to before me this 22ND day of February, 2016, by Michael P. Synan, proved to me on the basis of satisfactory evidence to be the person who appeared before me.

Alicine Francois
Notary Public

Commission Expires on: October 3, 2020

ALICINE E. FRANCOIS
NOTARY PUBLIC
Commonwealth of Massachusetts
My Commission Expires
October 3, 2020

Exhibit No. ES-301

Benefits Administration Savings Exhibit

Eversource Energy Service Company

Eversource Energy Service Company
Benefits Administration Savings Exhibit

(A)	(B) 2012	(C) 2013	(D) 2014	(E) 2015	(F) Total
	Savings				
1 Savings	$ -	$ 27,206,422 (a)	$ 27,206,422	$ 27,886,582	
2 Inflation Rate (b)			2.50%	1.40%	
3 Total Benefits Administration Savings ((Ln 1 * Ln 2) + Ln 1)	$ -	$ 27,206,422	$ 27,886,582	$ 28,276,995	
4 Capitalization Rate (c)		34.92%	33.78%	38.40%	
5 Total O&M Savings (Ln 3*(1-Ln 4))	$ -	$ 17,705,939	$ 18,466,495	$ 17,418,629	
6 Total Capitalized Savings (Ln 3-Ln 5)	$ -	$ 9,500,483	$ 9,420,088	$ 10,858,366	
7 Depreciation Rate (d)		3.32%	3.22%	3.30%	
8 Return + Depreciation Rate + Property Tax Rate (e)		17.22%	16.48%	16.66%	
Capitalized Savings, adjusted for Depreciation					
9 2012	$ -	$ -	$ -	$ -	
10 2013	$ -	$ 9,500,483	$ 9,194,567 (f)	$ 8,883,797 (g)	
11 2014	$ -	$ -	$ 9,420,088	$ 9,109,225 (h)	
12 2015	$ -	$ -	$ -	$ 10,858,366	
13 Total (Sum Ln 9-Ln 12)	$ -	$ 9,500,483	$ 18,614,654	$ 28,851,387	
14 Revenue Requirements for the Capitalized Accounts (Ln 8 * Ln 13)	$ -	$ 1,635,602	$ 3,067,695	$ 4,806,641	
15 Benefits Savings and Revenue Requirements (Ln 5 + Ln 14)	$ -	$ 19,341,541 (i)	$ 21,534,190 (i)	$ 16,668,952 (j)	$ 57,544,684

(G) Allocation to Transmission:	(H) Allocation %	(I)= (B), Ln 15 *(H) 2012	(J)= (C), Ln 15 *(H) 2013	(K)= (D), Ln 15 *(H) 2014	(L)= (E), Ln 15 *(H) 2015	(M)= (I) + (J) + (K) + (L) Total
16 CL&P	13.06% (k)	$ -	$ 2,526,005	$ 2,812,365	$ 2,176,965	$ 7,515,336
17 NSTAR Electric	6.64% (k)	$ -	$ 1,284,278	$ 1,429,870	$ 1,106,818	$ 3,820,967
18 PSNH	2.82% (k)	$ -	$ 545,431	$ 607,264	$ 470,064	$ 1,622,760
19 WMECO	2.50% (k)	$ -	$ 483,539	$ 538,355	$ 416,724	$ 1,438,617
20 Total Transmission (Sum Ln 16- Ln 19)	25.02%	$ -	$ 4,839,254	$ 5,387,854	$ 4,170,572	$ 14,397,680

(a) Exhibit No. ES-301, Page 2, Line 11 (B)
(b) Source of Inflation Rate is the Employment Cost Index report, Table A, Private Industry, Benefits, 12-month, not seasonally adjusted value obtained from the Bureau of Labor Statistics, website, www.bls.gov.
(c) Capitalization Rate represents the portion of Employee Benefit costs which were included in capitalized FERC accounts in the given year based on queries of Eversource accounting database.
(d) Depreciation Rate is calculated using Depreciation Expense from FERC Form 1, p336, Ln 12 divided by Net Utility Plant from FERC Form 1, p 110, Ln 6.
(e) Return Rate calculation is consistent with method as filed in the PTO AC Annual Informational Filing; return on equity (ROE) component is based on Eversource Distribution companies allowed ROE to be consistent with the merger cost/savings report submitted for state regulatory purposes. Depreciation Rate component see (g) above. Property Tax Rate component is calculated as Property Tax Expense divided by Net Utility Plant from FERC Form 1, p 110, Ln 6.

(f) Capitalized Savings, adjusted for Depreciation is calculated as (C), Ln 6 * (1-(D), Ln 7), for number of periods since initial savings
(g) Capitalized Savings, adjusted for Depreciation is calculated as (C), Ln 6 * (1-(E), Ln 7), for number of periods since initial savings
(h) Capitalized Savings, adjusted for Depreciation is calculated as (D), Ln 6 * (1-(E), Ln 7), for number of periods since initial savings
(i) Exhibit No. ES-103, Page 4, Line 4
(j) Annual savings multiplied by .75 to prorate and only include savings through September 30, 2015.
(k) Source is Exhibit No. ES-115

Eversource Energy Service Company
Benefits Administration Savings Exhibit

	(A) Benefits Type		Savings (B) 2013	
1	Medical	$	2,970,105	
2	Prescription	$	2,295,918	
3	Dental Plan	$	2,130,411	
4	Vision	$	136,893	
5	Total Benefit Savings (Sum Ln 1 thru Ln 4):	$	7,533,327	(a)
6	Benefit Savings related to Labor:	$	(3,026,905)	(b)
7	Total Active Employee Health Expense Savings (Sum Ln 5 - Ln 6):	$	4,506,422	
8	Retiree Health Benefits - Pre-65:	$	12,500,000	(c)
9	Retiree Health Benefits - Post-65:	$	10,200,000	(d)
10	Total Retiree Employee Health Expense Savings (Ln 8 + Ln 9):	$	22,700,000	
11	Total Benefit Administration Savings (Ln 7 + Ln 10):	$	27,206,422	

(a) Exhibit No. ES-301, Page 3, Line 5 (D)
(b) Exhibit No. ES-301, Page 4, Line 4 (D)
(c) Estimated savings to retiree health expense due to adjustment to the methodology for setting rates for Legacy NSTAR pre-Medicare retirees.
(d) Estimated savings to retiree health expense due to change in the prescription drug coverage for Legacy NU and Legacy NSTAR post-Medicare retirees.

Eversource Energy Service Company
Benefits Administration Savings Exhibit

		Expenses		Savings
	(A)	(B)	(C)	(D) = (B) - (C)
	Benefits Type	2012	2013	2013
1	Medical	$ 87,608,358	$ 84,638,253	$ 2,970,105
2	Prescription	$ 21,559,470	$ 19,263,552	$ 2,295,918
3	Dental Plan	$ 7,303,136	$ 5,172,725	$ 2,130,411
4	Vision	$ 860,048	$ 723,155	$ 136,893
5	Total (Sum Ln 1- Ln 4)	$ 117,331,012	$ 109,797,685	$ 7,533,327

Eversource Energy Service Company
Benefits Administration Savings Exhibit

	(A)		(B) 2012			(C) 2013		Savings (Costs) (D) = (B) -(C) Total	
	Adjustment to Benefits Savings Related to Labor Savings:								
1	2012 Current Year Benefit Savings	$	1,222,431	(a)				$	1,222,431
2	2012 Annualized Benefit Savings				$	3,635,282	(b)	$	(3,635,282)
3	2013 Current Year Benefit Savings				$	614,055	(c)	$	(614,055)
4	Total Benefits Related to Labor Savings (Sum Ln 1- Ln 3)	$	1,222,431		$	4,249,336		$	(3,026,905)

(a) Exhibit No. ES-105, Page 14, Line 188 (H)
(b) Exhibit No. ES-105, Page 18, Line 188 (P)
(c) Exhibit No. ES-105, Page 21, Line 48 (H)

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Eversource Energy Service Company **)** **Docket No. ER16-___-000**

ATTESTATION

Christine L. Vaughan, attests that she is Vice President of Rates and Regulatory Requirements of Eversource Energy Service Company and that, to the best of her knowledge, information, and belief, the cost of service materials and supporting data submitted as part of this filing are true, accurate, and current representations of Eversource Energy's operating companies' books, budgets, or other company documents.

C. Vaughan
____
Christine L. Vaughan

Subscribed and sworn to before me this 22 day of February, 2016, by Christine L. Vaughan, proved to me on the basis of satisfactory evidence to be the person who appeared before me.

Barbara J. Murphy
Notary Public

Commission Expires on: March 30, 2018

BARBARA J. MURPHY
Notary Public
COMMONWEALTH OF MASSACHUSETTS
My Commission Expires
March 30, 2018

APPENDIX E

PROTECTIVE AGREEMENT

<u>**FORM OF PROTECTIVE AGREEMENT**</u>

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Eversource Energy Service Company) Docket No. ER16-___-000

PROTECTIVE AGREEMENT

1. This Protective Agreement shall govern the use of all Protected Materials produced by, or on behalf of, any Participant. Notwithstanding any order terminating this proceeding, this Protective Agreement shall remain in effect until specifically modified or terminated by the Federal Energy Regulatory Commission ("Commission").

2. This Protective Agreement applies to the following two categories of materials: (A) A Participant may designate as protected those materials which customarily are treated by that Participant as sensitive or proprietary, which are not available to the public, and which, if disclosed freely, would subject that Participant or its customers to risk of competitive disadvantage or other business injury; and (B) A Participant shall designate as protected those materials which contain critical energy infrastructure information, as defined in 18 C.F.R. § 388.113(c)(1) ("Critical Energy Infrastructure Information").

3. Definitions — For purposes of this Protective Agreement.

(a) The term "Participant" shall mean a Participant as defined in 18 C.F.R. §385.102(b).

(b) (1) The term "Protected Materials" means (A) materials provided by a Participant and designated by such Participant as protected; (B) any information contained in or obtained from such designated materials; (C) any other materials which are made subject to this Protective Agreement by the Commission, by any court or other body having appropriate authority, or by agreement of the Participants; (D) notes of Protected Materials; and (E) copies of Protected Materials. The Participant producing the Protected Materials shall physically mark them, at least on the first page of each document, as "PROTECTED MATERIALS" or with words of similar import as long as the term "Protected Materials" is included in that designation to indicate that they are Protected Materials. If the Protected Materials contain Critical Energy Infrastructure Information, the Participant producing such information shall additionally mark on each page containing such information the words "Contains Critical Energy Infrastructure Information - Do Not Release."

(2) The term "Notes of Protected Materials" means memoranda, handwritten notes, or any other form of information (including electronic form) which copies or discloses materials described in Paragraph 5. Notes of Protected Materials are subject to the same

restrictions provided in this order for Protected Materials except as specifically provided in this Protective Agreement.

(3) Protected Materials shall not include (A) any information or document contained in the files of the Commission, or any other federal or state agency, or any federal or state court, unless the information or document has been determined to be protected by such agency or court, or (B) information that is public knowledge, or which becomes public knowledge, other than through disclosure in violation of this Protective Agreement, or (C) any information or document labeled as "Non-Internet Public" by a Participant, in accordance with Paragraph 30 of FERC Order No. 630, FERC Stat. & Reg. ¶ 31,140. Protected Materials do include any information or document contained in the files of the Commission that has been designated as Critical Energy Infrastructure Information.

(c) By signing this Protective Agreement, a Participant that has been granted access to Protected Materials certifies its understanding that such access to Protected Materials is provided pursuant to the terms and restrictions of this Protective Agreement, and that such Participants have read the Protective Agreement and agree to be bound by it.

(d) The term "Reviewing Representative" shall mean a person who has executed this Protective Agreement, except that members of the Commission's Staff need not execute, and who is:

(1) Commission Staff;

(2) an attorney who has made an appearance in this proceeding for a Participant;

(3) attorneys, paralegals, and other employees associated for purposes of this case with an attorney described in Paragraph (2);

(4) an expert or an employee of an expert retained by a Participant for the purpose of advising, preparing for or testifying in this proceeding;

(5) a person designated as a Reviewing Representative by order of the Commission; or

(6) employees or other representatives of Participants appearing in this proceeding with significant responsibility for this docket.

4. Protected Materials shall be made available under the terms of this Protective Agreement only to Participants and only through their Reviewing Representatives as provided in Paragraphs 7-9.

5. Protected Materials shall remain available to Participants until the later of the date that an order terminating this proceeding becomes no longer subject to judicial review, or the date that any other Commission proceeding relating to the Protected Material is concluded and no longer subject to judicial review. If requested to do so in writing after that date, the Participants shall,

within fifteen days of such request, return the Protected Materials (excluding Notes of Protected Materials) to the Participant that produced them, or shall destroy the materials, except that copies of filings, official transcripts and exhibits in this proceeding that contain Protected Materials, and Notes of Protected Material may be retained, if they are maintained in accordance with Paragraph 6, below. Within such time period each Participant, if requested to do so, shall also submit to the producing Participant an affidavit stating that, to the best of its knowledge, all Protected Materials and all Notes of Protected Materials have been returned or have been destroyed or will be maintained in accordance with Paragraph 6. To the extent Protected Materials are not returned or destroyed, they shall remain subject to the Protective Agreement.

6. All Protected Materials shall be maintained by the Participant in a secure place. Access to those materials shall be limited to those Reviewing Representatives specifically authorized pursuant to Paragraphs 8-9. The Secretary shall place any Protected Materials filed with the Commission in a non-public file. By placing such documents in a non-public file, the Commission is not making a determination of any claim of privilege. The Commission retains the right to make determinations regarding any claim of privilege and the discretion to release information necessary to carry out its jurisdictional responsibilities. For documents submitted to Commission Staff ("Staff"), Staff shall follow the notification procedures of 18 C.F.R. § 388.112 before making public any Protected Materials.

7. Protected Materials shall be treated as confidential by each Participant and by the Reviewing Representative in accordance with this Protective Agreement executed pursuant to Paragraph 9. Reviewing Representatives that are Commission Staff are required to comply with the requirements of this Protective Agreement but need not execute this Protective Agreement. Protected Materials shall not be used except as necessary for the conduct of this proceeding, nor shall they be disclosed in any manner to any person except a Reviewing Representative who is engaged in the conduct of this proceeding and who needs to know the information in order to carry out that person's responsibilities in this proceeding. Reviewing Representatives may make copies of Protected Materials, but such copies become Protected Materials. Reviewing Representatives may make notes of Protected Materials, which shall be treated as Notes of Protected Materials if they disclose the contents of Protected Materials.

8. (a) If a Reviewing Representative's scope of employment includes the marketing of energy or the buying or selling of fossil generating assets, the direct supervision of any employee or employees whose duties include the marketing of energy or the buying or selling of fossil generating assets, the provision of consulting services to any person whose duties include the marketing of energy or the buying or selling of fossil generating assets, or the direct supervision of any employee or employees whose duties include the marketing of energy or the buying or selling of fossil generating assets, such Reviewing Representative may not use information contained in any Protected Materials obtained through this proceeding to give any Participant or any competitor of any Participant, including its own employees or the employees of the party it represents, a commercial advantage or any non-public information regarding operation of fossil generating assets.

(b) In the event that a Participant wishes to designate as a Reviewing Representative a person not described in Paragraph 3(d) above, the Participant shall seek agreement from the

Participant providing the Protected Materials. If an agreement is reached that person shall be a Reviewing Representative pursuant to Paragraphs 3(d) above with respect to those materials. If no agreement is reached, the Participant shall submit the disputed designation to the Commission for resolution.

9. (a) A Reviewing Representative shall not be permitted to inspect, participate in discussions regarding, or otherwise be permitted access to Protected Materials pursuant to this Protective Agreement unless that Reviewing Representative has first executed this Protective Agreement provided that if an attorney qualified as a Reviewing Representative has executed such agreement, the paralegals, secretarial and clerical personnel under the attorney's instruction, supervision or control need not do so. A copy of each Protective Agreement shall be provided to counsel for the Participant asserting confidentiality prior to disclosure of any Protected Material to that Reviewing Representative.

(b) Attorneys qualified as Reviewing Representatives are responsible for ensuring that persons under their supervision or control comply with this Protective Agreement.

10. Any Reviewing Representative may disclose Protected Materials to any other Reviewing Representative as long as the disclosing Reviewing Representative and the receiving Reviewing Representative both have executed a Protective Agreement. In the event that any Reviewing Representative to whom the Protected Materials are disclosed ceases to be engaged in these proceedings, or is employed or retained for a position whose occupant is not qualified to be a Reviewing Representative under Paragraph 3(d), access to Protected Materials by that person shall be terminated. Even if no longer engaged in this proceeding, every person who has executed a Protective Agreement shall continue to be bound by the provisions of this Protective Agreement.

11. Subject to Paragraph 17, the Commission shall resolve any disputes arising under this Protective Agreement. Prior to presenting any dispute under this Protective Agreement to the Commission, the parties to the dispute shall use their best efforts to resolve it. Any Participant that contests the designation of materials as protected shall notify the party that provided the protected materials by specifying in writing the materials whose designation is contested. This Protective Agreement shall automatically cease to apply to such materials five (5) business days after the notification is made unless the designator, within said 5-day period, files a motion with the Commission, with supporting affidavits, demonstrating that the materials should continue to be protected. In any challenge to the designation of materials as protected, the burden of proof shall be on the participant seeking protection. If the Commission finds that the materials at issue are not entitled to protection, the procedures of Paragraph 17 shall apply. The procedures described above shall not apply to protected materials designated by a Participant as Critical Energy Infrastructure Information. Materials so designated shall remain protected and subject to the provisions of this Protective Agreement, unless a Participant requests and obtains a determination from the Commission's Critical Energy Infrastructure Information Coordinator that such materials need not remain protected.

12. All copies of all documents reflecting Protected Materials, including the portion of the hearing testimony, exhibits, transcripts, briefs and other documents which refer to Protected

Materials, shall be filed and served in sealed envelopes or other appropriate containers endorsed to the effect that they are sealed pursuant to this Protective Agreement. Such documents shall be marked "PROTECTED MATERIALS" and shall be filed under seal and served under seal upon the Commission and all Reviewing Representatives who are on the service list. Such documents containing Critical Energy Infrastructure Information shall be additionally marked "Contains Critical Energy Infrastructure Information - Do Not Release." For anything filed under seal, redacted versions or, where an entire document is protected, a letter indicating such, will also be filed with the Commission and served on all parties on the service list. Counsel for the producing Participant shall provide to all Participants who request the same, a list of Reviewing Representatives who are entitled to receive such material. Counsel shall take all reasonable precautions necessary to assure that Protected Materials are not distributed to unauthorized persons.

If any Participant desires to include, utilize or refer to any Protected Materials or information derived therefrom in testimony or exhibits during these proceedings in such a manner that might require disclosure of such material to persons other than reviewing representatives, such Participant shall first notify both counsel for the disclosing participant and the Commission of such desire, identifying with particularity each of the Protected Materials. Thereafter, use of such Protected Material will be governed by procedures determined by the Commission.

13. Nothing in this Protective Agreement shall be construed as precluding any Participant from objecting to the use of Protected Materials on any legal grounds.

14. Nothing in this Protective Agreement shall preclude any Participant from requesting the Commission, or any other body having appropriate authority, to find that this Protective Agreement should not apply to all or any materials previously designated as Protected Materials pursuant to this Protective Agreement. The Commission may alter or amend this Protective Agreement as circumstances warrant at any time during the course of this proceeding.

15. Each party governed by this Protective Agreement has the right to seek changes in it as appropriate from the Commission.

16. All Protected Materials filed with the Commission, or any other judicial or administrative body, in support of, or as a part of, a motion, other pleading, brief, or other document, shall be filed and served in sealed envelopes or other appropriate containers bearing prominent markings indicating that the contents include Protected Materials subject to this Protective Agreement. Such documents containing Critical Energy Infrastructure Information shall be additionally marked Contains Critical Energy Infrastructure Information — Do Not Release."

17. If the Commission finds at any time in the course of this proceeding that all or part of the Protected Materials need not be protected, those materials shall, nevertheless, be subject to the protection afforded by this Protective Agreement for three (3) business days from the date of issuance of the Commission's decision. None of the Participants waives its rights to seek additional administrative or judicial remedies after the Commission's decision respecting Protected Materials or Reviewing Representatives, or the Commission's denial of any appeal

thereof. The provisions of 18 C.F.R. §§ 388.112 and 388.113 shall apply to any requests for Protected Materials in the files of the Commission under the Freedom of Information Act. (5 U.S.C. § 552).

18. Nothing in this Protective Agreement shall be deemed to preclude any Participant from independently seeking through discovery in any other administrative or judicial proceeding information or materials produced in this proceeding under this Protective Agreement.

19. None of the Participants waives the right to pursue any other legal or equitable remedies that may be available in the event of actual or anticipated disclosure of Protected Materials.

20. The contents of Protected Materials or any other form of information that copies or discloses Protected Materials shall not be disclosed to anyone other than in accordance with this Protective Agreement and shall be used only in connection with this (these) proceeding(s). Any violation of this Protective Agreement executed hereunder shall constitute a violation of an order of the Commission.

[The next page is the signature page]

IN WITNESS WHEREOF, Eversource Energy Service Company and [the undersigned Recipient] each has caused this Protective Agreement to be signed by its duly authorized representative as of the date set forth below.

By (Recipient):___________________________

Title:___________________________________

Representing:____________________________

Date:___________________________________

By:____________________________________

Title:___________________________________

Representing: Eversource Energy Service Company

Date:___________________________________

ATTACHMENT F
ANNUAL TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirements for each PTO will reflect the PTO's costs with respect to Pool Supported PTF and the HTF, including costs attributable to those PTOs deemed to own or support PTF pursuant to Section II.49 of the Tariff. The Transmission Revenue Requirements will be an annual calculation based on the previous year's calendar data as shown, in the case of PTOs that are subject to the Commission's jurisdiction, in the PTO's FERC Form 1 report for that year; provided, however, that if a PTO is deemed to own or support PTF pursuant to Section II.49 of the Tariff, such PTO may include the costs as incurred by its Related Person for PTF facilities and Transmission Support Expenses as the basis for establishing its initial and subsequent Annual Transmission Revenue Requirements, only until such PTO has a full calendar year of cost data under its ownership. Such PTO's costs will be determined from FERC Form 1 data if available, or if not available, from other supporting data certified by an auditor of the PTO or Related Person, and in a format comparable to that used to report such costs in FERC Form 1. Such costs shall be based on actual data in lieu of allocated data if specifically identified in the Form 1 report in accordance with the following formula and Schedule 12:

I. The Transmission Revenue Requirement shall equal the sum of the PTO's (A) Return and Associated Income Taxes, (B) Transmission Depreciation and Amortization Expense, (C) Transmission Related Amortization of Loss on Reacquired Debt, (D) Transmission Related Amortization of Investment Tax Credits, (E) Transmission Related Municipal Tax Expense, (F) Transmission Related Payroll Tax Expense, (G) Transmission Operation and Maintenance Expense, (H) Transmission Related Administrative and General Expense, (I) Transmission Related Integrated Facilities Charges, minus (J) Transmission Support Revenue, plus (K) Transmission Support Expense, plus (L) Transmission Related Expense from Generators, plus (M) Transmission Related Taxes and Fees Charge, minus (N) Revenue for Short-Term service under the OATT and (O) Transmission Rents Received from Electric Property.

The details for implementation of Attachment F, as well as the definitions of the terms used in the Attachment F formula, shall be established in accordance with the Attachment F Implementation Rule contained in this OATT.

ATTACHMENT F
IMPLEMENTATION RULE

This rule sets forth details with respect to the determination each year of the Transmission Revenue Requirements for each PTO. Such Transmission Revenue Requirements shall reflect the PTO's costs for Pool Transmission Facilities ("PTF") and the Highgate Transmission Facilities ("HTF"), including costs attributable to those PTOs deemed to own or support PTF pursuant to Section II.49 of the Tariff. The Transmission Revenue Requirements for each PTO will reflect the PTO's costs with respect to Pool Supported PTF and the HTF. The Transmission Revenue Requirements will be an annual calculation based on the previous year's calendar data as shown, in the case of PTOs which are subject to the Commission's jurisdiction, in the PTO's FERC Form 1 report for that year; provided, however, that if a PTO is deemed to own or support PTF, such PTO may include the costs as incurred by its Related Person for PTF facilities and Transmission Support Expenses as the basis for establishing its initial and subsequent Annual Transmission Revenue Requirements, only until such PTO has a full calendar year of cost data under its ownership. Such PTO's costs will be determined from FERC Form 1 data if available, or if not available, from other supporting data certified by an auditor of the PTO or Related Person, and in a format comparable to that used to report such costs in FERC Form 1. Such costs shall be based on actual data in lieu of allocated data if specifically identified in the Form 1 report in accordance with the following formula and Schedule 12. The HTF Transmission Revenue Requirements shall be subject to the limitations of inclusion of such costs as set forth in Appendix B to this Attachment. The owners of the HTF, or their designated agent, will submit the annual HTF Transmission Revenue Requirements calculation based on the previous calendar year's cost data from their FERC Form 1 or equivalent information from their official books and records, as appropriate.

The Post-96 Transmission Revenue Requirement for each PTO that is based on data for calendar year 2004 or later shall include an Incremental Return and Associated Income Taxes on the PTO's PTF transmission plant investments included in the Regional System Plan and placed in-service on or after January 1,2004 (such investments referred to herein as "Post-2003 PTF Investment"). The Incremental Return and Associated Income Taxes for Post-2003 PTF Investment shall incorporate an incentive ROE adder of 100 basis points for plant investment placed in service by December 31, 2008 or as otherwise permitted in Docket Nos. ER04-157, et al. for any projects included in the RSP, and shall incorporate any incentive ROE adder approved by the FERC under Order No. 679 for other plant investments and for MPRP CWIP and NEEWS CWIP. The total ROE for any project, including any authorized ROE incentives for Post-2003 PTF Investment and any other incentive ROE approved by FERC under Order

No. 679 shall be capped by the top of the applicable zone of reasonableness determined by FERC for the relevant period. The data used in determining each PTO's Incremental Return and Associated Taxes for Post-2003 Investment shall be based on actual data in lieu of allocated data if specifically identified in the PTO's accounting records.

The Post-1996 Pool PTF Rate, as calculated pursuant to Schedule 9, shall include for each PTO a Forecasted Transmission Revenue Requirement calculated in accordance with Appendix C to this Attachment F Implementation Rule. Additionally, the Pre-1997 and Post-1996 Pool PTF Rates shall include an Annual True-up calculated in accordance with Appendix C to this Attachment F Implementation Rule.

The PTOs shall make an annual informational filing on or before July 31 of each year showing the Pool PTF Rate in effect for the period beginning June 1 of that year through May 31 of the subsequent year.Further, the informational filing with respect to the determination of the Pool PTF Rate will include a breakdown by PTO of the amount of the change in PTF and HTF investment during the prior year and the PTF and HTF retirements or additions causing such change to beginning and end-of-year PTF balances and HTF balances (although beginning-of-year PTF balances and HTF balances are not used in the formula itself), and any additions to PTF and HTF, retirements of PTF and HTF, and reclassifications of PTF and HTF during the year for each PTO. If there are any corrections made to the information reflected in the informational filing after it has been submitted, the PTOs will file corrections to the informational filing. At least forty-five days before the informational filing is made with the Commission, the PTOs shall make available to Transmission Customers and any other interested parties a draft of the proposed filing for review and comment prior to the filing by posting such draft on the ISO website. The filing of the information filing does not re-open the formula rate set forth below for review, but rather is contestable only with respect to the accuracy of the information contained in the informational filing.

The ISO shall have the discretion to conduct audits of such charges, with advisory Stakeholder input on the scope of audit, including on any agreed-upon procedures to be used by the auditor. In this provision, the term “agreed-upon procedures” shall have the meaning afforded to it by the American Institute of Certified Public Accountants.

I. DEFINITIONS

Capitalized terms not otherwise defined in the Tariff and as used in this rule have the following definitions:

A. ALLOCATION FACTORS

1. Transmission Wages and Salaries Allocation Factor shall equal the ratio of Transmission-related direct wages and salaries including those of affiliated Companies to the PTO's total direct wages and salaries including those of the Affiliates' Companies and excluding administrative and general wages and salaries.

2. PTF/HTF Transmission Plant Allocation Factor shall equal the ratio of PTF/HTF Transmission Plant to Total Investment in Transmission Plant, excluding capital leases in the Phase I/II HVDC-TF (Phase I/II HVDC-TF Leases).

3. Plant Allocation Factor shall equal the ratio of the sum of Total Investment in Transmission Plant, excluding Phase I/II HVDC-TF Leases, and Transmission Related Intangible and General Plant to Total Plant in service excluding Phase I/II HVDC-TF Leases.

B. TERMS

Administrative and General Expense shall equal the PTO's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928 and 930.1 and excluding Merger-Related Costs included in FERC Account Nos. 920-935 (other than those in FERC Account Nos. 924, 928 and 930.1, which have already been excluded).

Amortization of Loss on Reacquired Debt shall equal the PTO's expenses as recorded in FERC Account No. 428.1.

Amortization of Investment Tax Credits shall equal the PTO's credits as recorded in FERC Account No. 411.4.

Depreciation Expense for Transmission Plant shall equal the PTO's transmission expenses as recorded in FERC Account No. 403.

General Plant shall equal the PTO's gross plant balance as recorded in FERC Account Nos. 389-399.

General Plant Depreciation and Amortization Expense shall equal the PTO's general expenses as recorded in FERC Account No. 403 and NSTAR Electric's FERC Account No. 404 for items subject to amortization.

General Plant Amortization Reserve shall equal NSTAR Electric's general reserve balance as recorded in FERC Account No. 111.

HTF Transmission Plant shall equal the PTO's balance of investment in the Highgate Transmission Facilities as recorded in FERC Account Nos. 350-359.

Intangible Plant shall equal NSTAR Electric's gross plant balance as recorded in FERC Account No. 303. The only allowable Intangible Plant for inclusion are software, patent or rights costs.

Intangible Plant Amortization Expense shall equal NSTAR Electric's amortization expenses as recorded in FERC Account Nos. 404-405. The only allowable Intangible Plant Amortization Expense for inclusion is the amortization of software, patent or rights costs.

Intangible Plant Amortization Reserve shall equal NSTAR Electric's amortization reserve balance as recorded in FERC Account No. 111. The only allowable Intangible Plant Amortization Reserve for inclusion is that related to the amortization of software, patent or rights costs.

Maine Power Reliability Program Construction Work In Progress ("MPRP CWIP") shall equal Central Maine Power Company's ("CMP's") MPRP CWIP balance as recorded in FERC Account No. 107 for costs determined to be Pool- Supported PTF in accordance with Schedule 12 of this OATT.

Merger-Related Costs shall equal NSTAR Electric Company's ("NSTAR Electric"), CL&P's, Public Service Company of New Hampshire's ("PSNH") and WMECO's amortized merger-related costs as authorized by FERC or by state regulatory order.

New England East-West Solution Construction Work in Progress ("NEEWS CWIP") shall equal the NEEWS CWIP balances of The Connecticut Light and Power Company ("CL&P") and Western Massachusetts Electric Company ("WMECO") and New England Power Company ("NEP") as recorded in FERC Account No. 107 for costs determined to be Pool-Supported PTF in accordance with Schedule 12 of this OATT.

Other Regulatory Assets/Liabilities - FAS 106 shall equal the net of the PTO's FAS 106 balance as recorded in FERC Account 182.3 and any FAS 106 balance as recorded in the PTO's FERC Account No. 254.

Other Regulatory Assets/Liabilities - FAS 109 shall equal the net of the PTO's FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in the PTO's FERC Account No. 254.

Payroll Taxes shall equal those payroll expenses as recorded in the PTO's FERC Account Nos. 408.1.

Phase I/II HVDC-TF Leases shall equal the PTO's balance in capital leases as recorded in FERC Account Nos. 350-359 and FERC Account Nos. 389-399.

Plant Held for Future Use shall equal the PTO's balance in FERC Account No.105.

Prepayments shall equal the PTO's prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal the PTO's expenses as recorded in FERC Account No. 924.

PTF Transmission Plant shall equal the PTO's transmission plant as defined in the Section II.49 of the OATT and determined in accordance with Appendix A of this Rule, which is entitled "Rules for Determining Investment To be Included in PTF."

PTF/HTF Transmission Plant Investment shall equal the PTO's (a) PTF Transmission Plant plus (b) HTF Transmission Plant.

Total Accumulated Deferred Income Taxes shall equal the net of the PTO's deferred tax balance as recorded in FERC Account Nos. 281-283 and the PTO's deferred tax balance as recorded in FERC Account No. 190.

Total Loss on Reacquired Debt shall equal the PTO's expenses as recorded in FERC Account 189.

Total Municipal Tax Expense shall equal the PTO's municipal tax expenses as recorded in FERC Account Nos. 408.1.

Total Plant in Service shall equal the PTO's total gross plant balance as recorded in FERC Account Nos. 301-399.

Total Transmission Depreciation Reserve shall equal the PTO's transmission reserve balance as recorded in FERC Account 108.

Transmission Merger-Related Costs shall equal NSTAR Electric's, CL&P's, PSNH's and WMECO's amortized merger-related transmission costs as authorized by FERC.

Transmission Operation and Maintenance Expense shall equal the PTO's expenses as recorded in FERC Account Nos. 560, 561.5-561.8, 562-564 and 566-573, and shall exclude all Phase I/II HVDC-TF expenses booked to accounts 560 through 573 and expenses already included in Transmission Support Expense, as described in Section K which are included in FERC Account Nos. 560-573.

Transmission Plant shall equal the PTO's Gross Plant balance as recorded in FERC Account Nos. 350-359.

Transmission Plant Materials and Supplies shall equal the PTO's balance as assigned to transmission, as recorded in FERC Account No. 154.

II. CALCULATION OF TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirement shall equal the sum of the PTO's (A) Return and Associated Income Taxes (including the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP), (B) Transmission Depreciation and Amortization Expense, (C) Transmission Related Amortization of Loss on Reacquired Debt, (D) Transmission Related Amortization of Investment Tax Credits, (E) Transmission Related Municipal Tax Expense, (F) Transmission Related Payroll Tax Expense, (G) Transmission Operation and Maintenance Expense, (H) Transmission Related Administrative and General Expenses, (I) Transmission Related Integrated Facilities Charges, minus (J) Transmission Support Revenue, plus (K) Transmission Support Expense, plus (L) Transmission-Related Expense from Generators, plus (M) Transmission Related Taxes and Fees Charge, minus (N) Revenue for Short-Term service under the OATT, (O) Transmission Rents Received from Electric Property and (P) Transmission Revenues from MEPCO Grandfathered Transmission Service Agreements. The Incremental Return and Associated Income Taxes for Post-2003 PTF Investment for each PTO shall be calculated using the investment base components specifically identified in Section A. 1 of the formula below.

A. <u>Return and Associated Income Taxes</u> shall equal the product of the Transmission Investment Base and the Cost of Capital Rate. To calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP, Transmission Investment Base will only include Sections II.A. 1 .(a), (d), (e), (k), and (1) in the manner indicated.

1. <u>Transmission Investment Base</u>

The Transmission Investment Base will be the year end balances of(a) PTF/HTF Transmission Plant, plus (b) Transmission Related Intangible and General Plant, plus (c) Transmission Plant Held for Future Use, less (d) Transmission Related Depreciation and Amortization Reserve, less (e) Transmission Related Accumulated Deferred Taxes, plus (f) Transmission Related Loss on Re.acquired Debt, plus (g) Other Regulatory Assets/Liabilities, plus (h) Transmission Prepayments, plus (i) Transmission Materials and Supplies, plus (j) Transmission Related Cash Working Capital, plus (k) MPRP CWIP, plus (l) NEEWS CWIP.

(a) <u>PTF Transmission Plant</u> will equal the balance of the PTO's PTF Investment in (a) Transmission Plant plus (b) HTF Transmission Plant. This value excludes (i) the PTO's Phase I/II HVDC-TF Leases, (ii) the portion of any facilities, the cost of which is directly assigned under Schedule 11 to the OATT, to the Transmission Customer or a Generator

Owner or Interconnection Requester, (iii) the Pre-1997 PTF gross plant investment associated with leased facilities occupied by the Phase II section of the Phase I/II HVDC-TF. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment, Post2003 PTF Transmission Plant shall be separately identified.

(b) Transmission Related Intangible and General Plant shall equal the sum of the PTO's balance of investment in Intangible Plant and General Plant multiplied by the Transmission Wages and Salaries Allocation Factor and the PTF/HTF Transmission Plant Allocation Factor.

(c) Transmission Plant Held for Future Use shall equal the PTO's balance of Transmission-related Plant Held for Future Use multiplied by the PTF/HTF Transmission Plant Allocation Factor.

(d) Transmission Related Depreciation and Amortization Reserve shall equal the PTO's balance of Total Transmission Depreciation Reserve, plus the balance of Transmission Related Intangible Plant Amortization Reserve, Transmission Related General Plant Depreciation Reserve and Transmission Related General Plant Amortization Reserve. Transmission Related Intangible Plant Amortization Reserve, Transmission Related General Plant Depreciation Reserve and Transmission Related General Plant Amortization Reserve shall equal the product of the sum of Intangible Plant Amortization Reserve, General Plant Depreciation Reserve and General Plant Amortization Reserve, and the Transmission Wages and Salaries Allocation Factor. This sum shall be multiplied by the PTF/HTF Transmission Plant Allocation Factor. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment, Transmission Depreciation Reserve associated with Post-2003 PTF Investment shall equal the PTO's balance of Total Transmission Depreciation Reserve multiplied by the ratio of Post-2003 PTF Transmission Plant to Total Investment in Transmission Plant, excluding capital leases in the Phase I/II HVDC-TF Leases.

(e) Transmission Related Accumulated Deferred Taxes shall equal the PTO's electric balance of Total Accumulated Deferred Income Taxes, multiplied by the Plant Allocation Factor, further multiplied by the PTF/HTF Transmission Plant Allocation Factor. To calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF

Investment, Transmission Related Accumulated Deferred Income Taxes associated with Post-2003 PTF Investment shall equal the PTO’s balance of total property-related accumulated deferred income taxes as recorded in FERC accounts 281 and 282, multiplied by the ratio of Total Investment in Transmission Plant, excluding Phase I/II HVDC-TF Leases, to Total Plant in Service excluding Phase I/II HVDC-TF Leases, further multiplied by the ratio of Post-2003 PTF Transmission Plant to Total Investment in Transmission Plant, excluding Phase I/II HVDC-TF Leases.

(f) Transmission Related Loss on Reacquired Debt shall equal the PTO’s electric balance of Total Loss on Reacquired Debt multiplied by the Plant Allocation Factor, further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

(g) Other Regulatory Assets/Liabilities shall equal the PTO’s electric balance of any deferred rate recovery of FAS 106 expenses multiplied by the Transmission Wages and Salaries Allocation Factor, plus the PTO’s electric balance of FAS 109 multiplied by the Plant Allocation Factor. This sum shall be multiplied by the PTF/HTF Transmission Plant Allocation Factor.

(h) Transmission Prepayments shall equal the PTO's electric balance of prepayments multiplied by the Transmission Wages and Salaries Allocation Factor and further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

(i) Transmission Materials and Supplies shall equal the PTO's electric balance of Transmission Plant Materials and Supplies, multiplied by the PTF/HTF Transmission Plant Allocation Factor.

(j) Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of the PTO's Transmission Operation and Maintenance Expense, Transmission Related Administrative and General Expense and Transmission Support Expense, to the extent that Transmission Support Expense exceeds Transmission Support Revenue included in Paragraph J of the formula.

(k) MPRP CWIP shall equal CMP's balance as recorded in FERC Account No. 107 for the MPRP as authorized by Commission order and in accordance with CMP's Accounting

Procedures for MPRP CWIP. In order to calculate the Incremental Return and Associated Income Taxes for MPRP CWIP, MPRP CWIP shall be separately identified.

(l) NEEWS CWIP shall equal CL&P, WMECO and NEP's balances as recorded in FERC Account No. 107 for the NEEWS as authorized by Commission order and in accordance with the companies' respective Accounting Procedures for NEEWS CWIP. In order to calculate the Incremental Return and Associated Income Taxes for NEEWS CWIP, NEEWS CWIP shall be separately identified.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) the PTO's Weighted Cost of Capital, plus (b) Federal Income Tax plus (e) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon the capital structure at the end of each year and will equal the sum of (i), (ii), and (iii) below. The Cost of Capital Rate to be used in calculating the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP, shall only reflect item (iii) below and shall apply in the manner indicated below.

(i) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity of the PTO's long-term debt then outstanding and the ratio that long-term debt is to the PTO's total capital.

(ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of the PTO's preferred stock then outstanding and the ratio that preferred stock is to the PTO's total capital.

(iii) the return on equity component, shall be the product of the allowed ROE of the PTO's common equity and the ratio that common equity is to the PTO's total capital. For pre-1997 and post-1996 assets, the ROE is 11.07%. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP, the incremental return on equity shall be the product of: (1) the PTO's incremental return on equity of 1.0% for plant investments associated with projects included in the RSP and placed in service by December 31, 2008 or otherwise permitted in Docket Nos. ER04-157, et al.; (2) any ROE incentive approved by the FERC under Order No. 679 for other plant investments and MPRP CWIP and NEEWS CWIP, provided that the total ROE for any project, including any such ROE incentives, shall be capped by the top of the applicable zone of reasonableness determined by FERC for the relevant period, and (3) the ratio that common equity is to the PTO's total capital) [1]

(b) Federal Income Tax shall equal

$$\frac{(A+[(C+B)/D])(FT)}{I\text{-}FT}$$

where FT is the Federal Income Tax Rate and A is the sum of the preferred stock component and the return on equity component, as determined in Sections ll.A.2.(a)(ii) and (iii) above, B is Transmission Related Amortization of Investment Tax Credits, as determined in Section II.D., below, C is the Equity AFUDC component of Transmission Depreciation Expense, as defined in Section ll.B., and D is Transmission Investment Base, as determined in Section II.A.1., above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP, the incremental Federal Income Tax shall equal

$$\frac{(A' * FT)}{(1\ \text{-}FT)}$$

where FT is the Federal Income Tax Rate and A' is the incremental return on equity component, as determined in Section II.A.2.(a)(iii) above.

(c) State Income Tax shall equal

$$\frac{(A+[(C+B)/D] + \text{Federal Income Tax})(ST)}{1\ \text{-}ST}$$

where ST is the State Income Tax Rate, A is the sum of the preferred stock component and return on equity component determined in Sections II.A.2.(a)(ii) and (iii) above, B is

[1] FERC Form-730 contains a list of transmission projects for which FERC has granted incentives under Order No. 679.

the Amortization of Investment Tax Credits as determined in Section ll.D.below, C is the equity AFUDC component of Transmission Depreciation Expense, as defined in Section II.B.. D is the Transmission Investment Base, as determined in II.A.1., above and Federal Income Tax is the rate determined in Section II.A.2.(b) above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP, the incremental State Income Tax shall equal

$$\frac{(A' + \text{Federal Income Tax})(ST)}{(1 - ST)}$$

where ST is the State Income Tax Rate, A' is the incremental return on equity component determined in Section II.A.2.(a)(iii) above, and Federal Income Tax is the rate determined in Section II.A.2.(b) above.

B. Transmission Depreciation and Amortization Expense shall equal the PTF/HTF Transmission Plant Allocation Factor, multiplied by the sum of (i) the PTO's Depreciation Expense for Transmission Plant, plus (ii) an allocation of Intangible Plant Amortization Expense and (iii) General Plant Depreciation and Amortization Expense calculated by multiplying the sum of (a) Intangible Plant Amortization Expense and (b) General Plant Depreciation and Amortization Expense by the Transmission Wages and Salaries Allocation Factor.

C. Transmission Related Amortization of Loss on Reacquired Debt shall equal the PTO's electric Amortization of Loss on Reacquired Debt multiplied by the Plant Allocation Factor, and further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

D. Transmission Related Amortization of Investment Tax Credits shall equal the PTO's electric Amortization of Investment Tax Credits multiplied by the Plant Allocation Factor, and further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

E. Transmission Related Municipal Tax Expense shall equal the PTO's total electric municipal tax expense multiplied by the Plant Allocation Factor, and further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

F. <u>Transmission Related Payroll Tax Expense</u> shall equal the PTO's total electric payroll tax expense, multiplied by the Transmission Wages and Salaries Allocation Factor, further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

G. <u>Transmission Operation and Maintenance Expense</u> shall equal the PTO's Transmission Operation and Maintenance Expenses multiplied by the PTF/HTF Transmission Plant Allocation Factor.

H. <u>Transmission Related Administrative and General Expenses</u> shall equal the sum of the PTO's (1) Administrative and General Expenses multiplied by the Transmission Wages and Salaries Allocation Factor, (2) Property Insurance multiplied by the Transmission Plant Allocation Factor, and (3) Expenses included in Account 928 (excluding Merger-Related Costs included in Account 928) related to FERC Assessments multiplied by Plant Allocation Factor, plus any other Federal and State transmission related expenses or assessments, plus specific transmission related expenses included in Account 930.1 plus Transmission Merger-Related Costs. This sum shall be multiplied by the PTF/HTF Transmission Plant Allocation Factor.

I. <u>Transmission Related Integrated Facilities Charges</u> shall equal the PTO's transmission payments to Affiliates for use of the PTF and HTF integrated transmission facilities of those Affiliates.

J. <u>Transmission Support Revenues</u> shall equal the PTO's revenue received for PTF and HTF transmission support but excluding the support payments to PTOs or their designee pursuant to Schedule 11 and excluding the support payments to PTOs or their designee pursuant to Schedule 12 Part 1(a) and Part B.2, and excluding support payments, if any, made to PTOs or their respective designee pursuant to Part II.C of this OATT.

K. <u>Transmission Support Expense</u> shall equal the expense paid by (1) PTOs, (2) Transmission Customers or (3) Related Persons pursuant to Section II.49 of the Tariff for PTF and HTF transmission support other than expenses for payments made for congestion rights or for transmission facilities or facility upgrades placed in service on or after January 1, 1997, where the support obligation is required to be borne by particular PTOs or other entities in accordance with the OATT. Transmission Support Expenses by any entity other than a PTO, included in this provision, shall be capped at that entity's annual payment for Regional Network Service or its Point To Point Service for each individual Point To Point transaction from the resource with which the support payment is associated.

L. Transmission-Related Expense from Generators shall equal the expenses from generators that both (1) the PTO Administrative Committee determines should be included as transmission expense as a result of the impact of such generators on reducing transmission costs that would otherwise be required to be paid by Transmission Customers and (2) are reflected in a filing made by the PTOs with the Commission under Section 205 of the Federal Power Act and accepted by the Commission for recovery under the OATT.

M. Transmission Related Taxes and Fees Charge shall include any fee or assessment imposed by any governmental authority on service provided under this Section which is not specifically identified under any other section of this rule.

N. Revenues for Short-Term service under the OATT shall be revenues distributed to each PTO for short term service provided under the OATT, received after March 1, 1999. These revenues will be credited pro-rata between pre-1997 and post-1996 PTF revenue requirements in proportion to pre-1997 and post-1996 PTF Transmission Plant.

O. Transmission Rents Received from Electric Property shall equal any Account 454 Rents from electric property, associated with PTF and HTF Transmission Plant as defined in Section II.A.1.(a) above but not reflected as a credit in Transmission Support Revenues in paragraph K of this Attachment.

P. Transmission Revenues from MGTSAs shall equal any MGTSA revenues recorded in Account 456.

APPENDIX A TO ATTACHMENT F
IMPLEMENTATION RULE RULES FOR DETERMINING
INVESTMENT TO BE INCLUDED IN PTF

Section A – Transmission Lines*

Section B – Terminal Facilities*

Section C – Right of Way*

Effective June 1, 1998

*The following provision shall apply to Sections A, B and C below:

Of those transmission facilities that are upgrades, modifications or additions to the New England Transmission System on and after January 1, 2004, only those that: (i) are rated 115kV or above, and (ii) otherwise meet the non-voltage criteria specified in Section II.49 of this OATT shall be classified as PTF. Those transmission facilities that were PTF on December 31, 2003, and any upgrades to such facilities that meet the definition of PTF specified in this OATT, shall remain classified as PTF for all purposes under the Transmission, Markets and Services Tariff.

Section A: Rules for Determining Transmission Line Investment to be Included in PTF

Pool Transmission Facilities (PTF) are the transmission facilities owned by PTO rated 69 kV or above required to allow energy from significant power sources to move freely on the New England transmission network, and include:

1. All transmission lines and associated facilities owned by the PTOs rated 69 kV and above, except:

   a. those which are required to serve local load only, thereby contributing little or no parallel capability to the transmission network,

   b. generator leads, which are defined as the radial transmission from a generator bus to the nearest point on the transmission network,

c. lines that are normally operated open.

d. those that are classified as MTF.

2. Terminal facilities (including substation facilities such as transformers, circuit breakers, and associated equipment) required to interconnect the lines which constitute PTF (see Section B).

3. If a PTO with significant generation in its system (initially 25 MW) is connected to the New England Transmission System and none of the transmission facilities owned by the PTO qualify to be included in PTF as defined in “1” and “2” above, then such PTO’s connection to PTF will constitute PTF if both of the following requirements are met for this connection:

a. The connection is rated 69 kV or above.

b. The connection is the principal transmission link between the PTO and the remainder of the ISO PTF network.

The PTF facilities covered by this provision shall consist of a single line from the point of connection on the transmission network to the first bus within the PTO’s system.

4. R/W and land required for the installation of PTF facilities listed in “1”, “2”, or “3” (see Section C).

The following examples indicate the intent of the above definitions:

a. Radial tap lines to local load are excluded.

b. Lines which loop, from two geographically separate points on the transmission network, the supply to the load bus from the transmission network are included.

c. Lines which loop, from two geographically separate points on the transmission network, the connections between a generator bus, and the transmission network are included.

d. Radial connection or connections from a generating station to a single substation or switching station on the transmission network are excluded unless the requirements of paragraph 3 above are met.

e. The cost of a PTF line will include only those costs associated with that line. When other facilities require rebuilding or undergrounding to permit the construction of a PTF facility, the investment costs in the relocated or undergrounded facility will not be included.

f. Where multiple circuit structures support a mixture of PTF and Non-PTF circuits, the total cost of the multiple circuit structures will be allocated between the circuits in accordance with the ratio of costs of comparable individual structures.

The PTOs shall review at least annually the status of transmission lines and related facilities and determine whether such facilities constitute PTF and shall prepare and keep current a schedule or catalog of PTF facilities.

All new facilities being installed should be properly classified at the time the facilities are approved under Section I.3.9 of the Transmission, Markets and Services Tariff.

Transmission facilities owned or supported by a Related Person of a PTO which are rated 69 kV or above and are required to allow Energy from significant power sources to move freely on the New England Transmission System shall also constitute PTF provided (i) such Related Person files with the ISO its consent to such treatment; and (ii) the ISO determines in consultation with the PTO Administrative Committee determines that treatment of the facility as PTF will facilitate accomplishment of the ISO's objectives. If such facilities constitute PTF pursuant to this paragraph, they shall be treated as "owned" or "supported," as applicable, by a PTO for purposes of the OATT and the other provisions of the TOA, including the ability to include the cost associated with such PTF and any Transmission Support Expenses for support of PTF made by its Related Person in that PTO's Annual Transmission Revenue Requirements pursuant to Attachment F of the OATT.

Section B: Rules for Determining Terminal Investment to be Included in PTF

Terminal Investment is investment associated with the terminal facilities of electrical lines, including substation facilities such as transformers, circuit breakers, disconnects and airbreaks, bus conductor, related protection equipment and other related facilities (see paragraph 7).

1. The investment in terminal facilities shall be included where these facilities are identifiable and serve directly for terminating and/or switching PTF lines.

2. In cases where a line terminal is used in conjunction with both PTF and Non-PTF lines and/or facilities, it will be considered a PTF facility providing the terminal facility is at 69 kV or above and carries any power flow at 69 kV or above through parallel paths within the interconnected network under normal operation. PTF equipment is any element of the transmission system in those parallel paths. Any equipment not in these parallel paths is Non-PTF.

3. Where line terminals are installed solely for Non-PTF facilities, and do not carry any power flow at 69 kV or above through parallel paths within the interconnected network under normal operation, such terminal cost shall not be included in PTF.

4. A two-winding transformer which connects PTF facilities at both terminals along with any switcher which can be identified as pertaining solely to the transformer, will be included in their entirety as PTF.

5. An autotransformer or three winding transformer which connects PTF facilities at two (2) or more terminals, along with any switchgear which can be identified as pertaining solely to the PTF-connected terminals of the transformer, will be included in their entirety as PTF. An autotransformer or three winding transformer which is connected to PTF at only one terminal will not be PTF.

6. When a transformer supplies only Non-PTF facilities, the entire transformer installation, including the high side disconnect switch or circuit breaker and associated structures or tap lines shall be excluded from PTF except for the portion of line terminal facilities covered by paragraph 2.

7. Other facilities – the investment in that portion of a multi-use substation or switching station which is identifiable as serving a PTF function shall be included in PTF, while the investment in

such facilities which are identifiable as serving a Non-PTF function shall be excluded. The investment in land, structures, ground mats, fences, ducts, lighting, etc., can often be identified and thus allocated. The investment in other facilities in the substation or switching station, excluding transformers, which are not identifiable as serving either a PTF or a Non-PTF function and general overheads shall be allocated to PTF on the basis of the ratio of the investment in those facilities identified as PTF to the sum of the investments in the facilities which are identified as serving PTF and Non-PTF functions; the equipment cost of power transformers shall not be included in this calculation for determining the division of investment, since this would produce a distorted balance.

8. Alternate method of allocating the cost of terminal facilities – In those cases where the major portion of the investment has been lumped and utility plant records do not permit the accurate assignment of costs to specific terminals, the total investment may be prorated to PTF and Non-PTF according to the number of terminals serving PTF and Non-PTF facilities.

9. In cases where microwave facilities are used in whole or part for PTF purposes, a prorated portion of such investment shall be included in PTF based on the PTF and Non-PTF functions served by the microwave facilities except where these facilities are otherwise supported under the Microwave Sharing Agreement dated June 1, 1970 among some of the New England utilities.

10. Generator unit transformers and generator circuit breakers shall be excluded from PTF, unless otherwise included by paragraphs 1 or 5.

11. In cases where remote control (Supervisory Control) and telemetering facilities are used in whole or in part for PTF purposes, a prorated portion of such investment shall be included in PTF based on the PTF and Non-PTF functions served by these facilities.

12. The PTO Administrative Committee may designate appropriate facilities as PTF.

Section C: Rules for Determining PTF R/W Costs

1. If a R/W has only PTF lines and no Non-PTF lines are expected to be added, the entire cost of the R/W is to be included as PTF.

2. If the R/W has only PTF lines but includes additional unused R/W which was purchased for future use by Non-PTF lines, the cost of the additional R/W is not to be included as PTF.

3. If the R/W contains both PTF and Non-PTF lines, the R/W cost to be assigned to PTF is to be determined as follows:

   a. Where new or additional R/W is required to permit the construction of PTF line(s) and the added R/W is adequate to contain the new PTF, the cost of the new R/W is to be assigned to the PTF line(s), (even if the PTF line is located on the old R/W).

   b. Where an existing R/W is used (without additional R/W), the amount allocated to PTF will be determined in accordance with paragraph 4.

   c. Where a R/W is widened, but the new facilities, either PTF or Non-PTF, require partial use of the existing R/W, the incremental cost of the new R/W will be assigned to the new facilities. The width of the original R/W will be added to the width of the new R/W and the combined width will be allocated between PTF and Non-PTF as in paragraph 4. The cost of the old R/W and the combined width will be allocated between PTF and Non-PTF as in paragraph 4. The cost of the old R/W will be allocated to the new facilities in proportion to the width of the old R/W assigned to the new facilities. Thus, the R/W for the new facilities will be the additional R/W plus a share of the old R/W.

4. In allocating R/W between PTF and Non-PTF lines, each shall bear a share of the R/W in accordance with the following formulae.

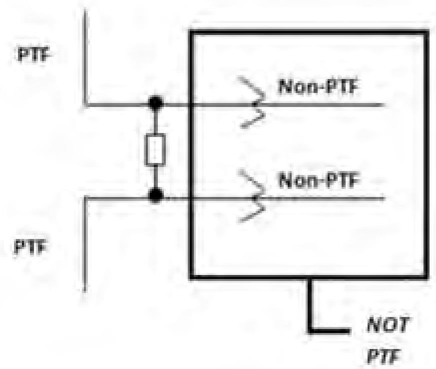
   a. Determine the R/W width required for each facility if constructed independently using appropriate type structures.

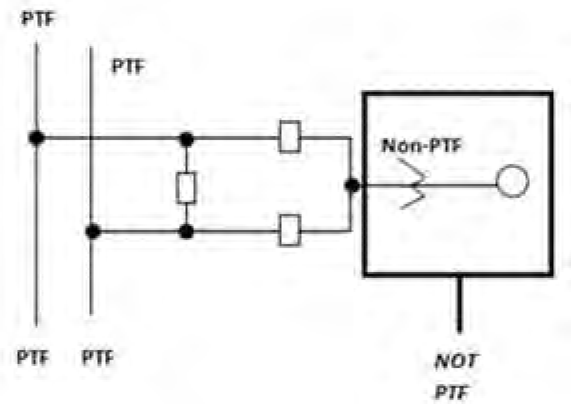
   b. Allocate the actual R/W width to each facility in the proportion its independent R/W requirement would be to the sum of the independent R/W requirements.

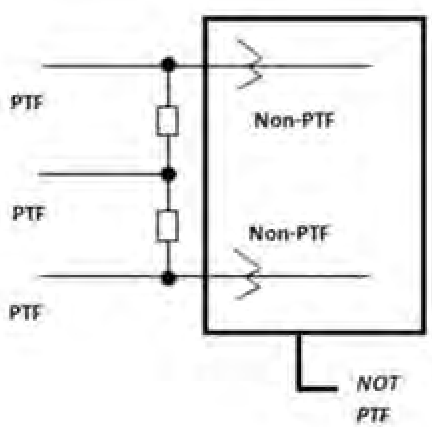
5. R/W and land held for future PTF facilities may be included in PTF facilities only if specifically approved by the PTO Administrative Committee included under paragraph 1.

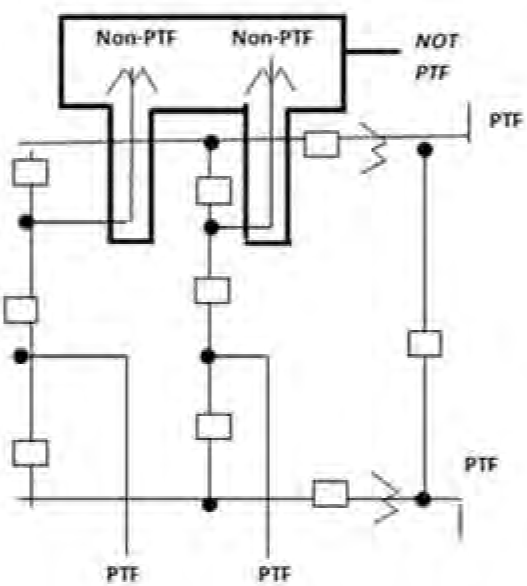
ATTACHMENT 1 TO APPENDIX A TO
ATTACHMENT F IMPLEMENTATION RULE

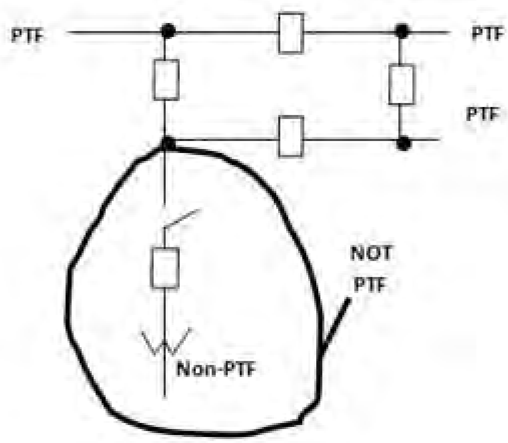
Examples of the Methods for Distinguishing PTF
from Non-PTF Terminal Facilities
in a Number of Typical Substation Configurations







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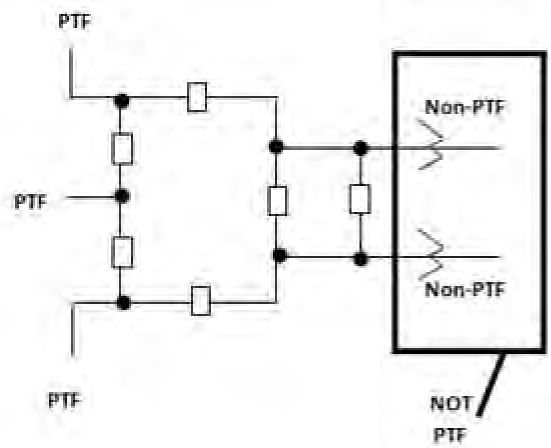
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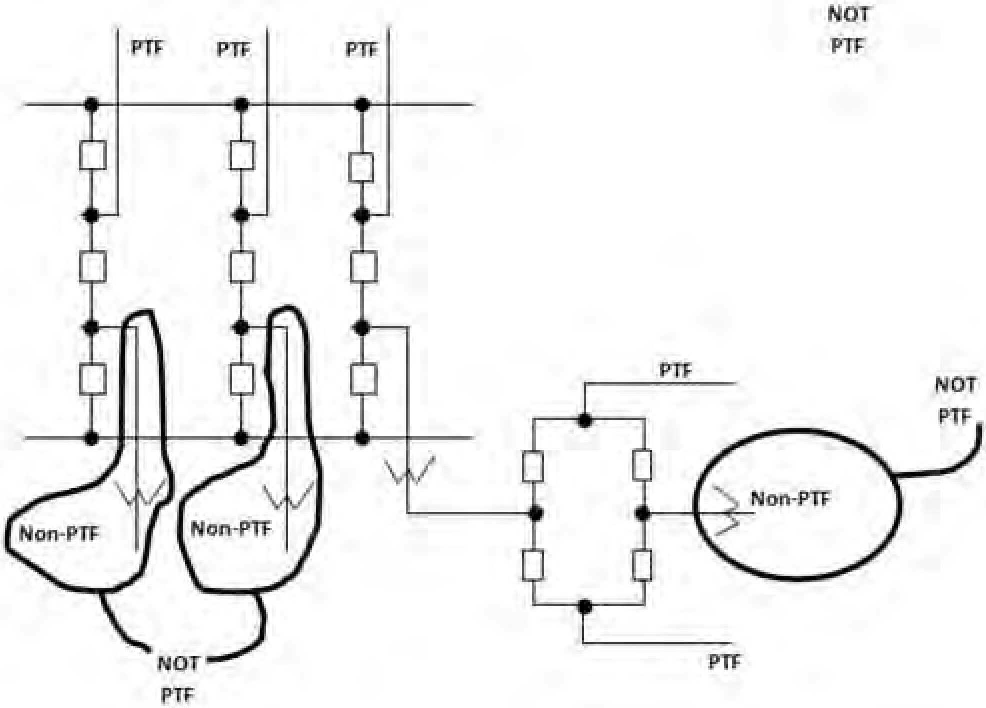
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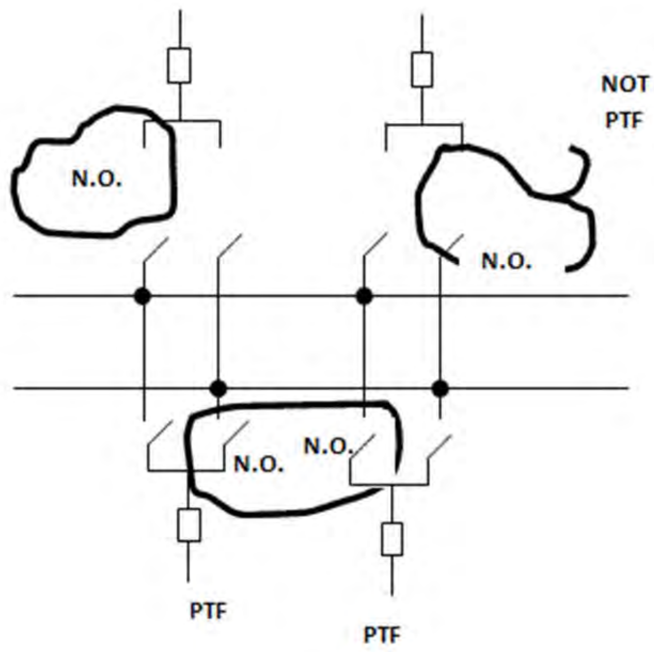
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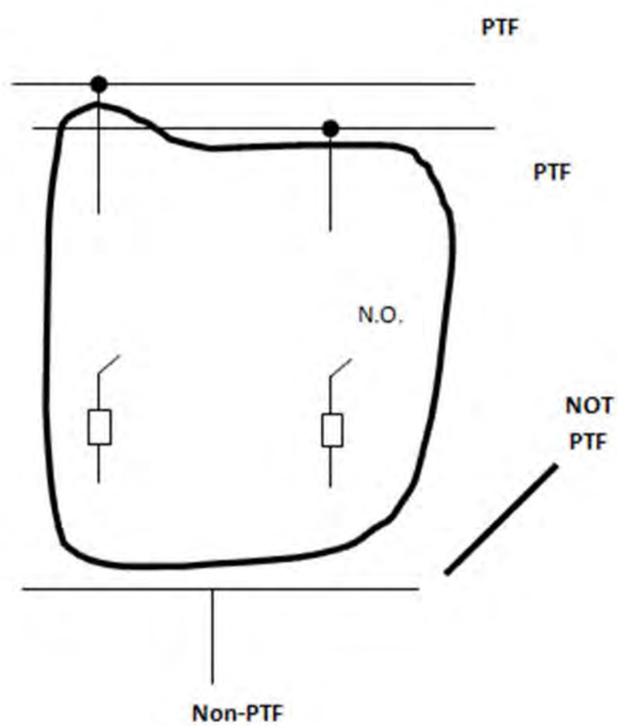
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APPENDIX B TO ATTACHMENT F IMPLEMENTATION RULE
HTF TRANSITION SCHEDULE

The inclusion of HTF Annual Transmission Revenue Requirements in Attachment F (and the calculation of the Pool PTF Rate) to this OATT will be limited by the provisions of this schedule.

VELCO, as a PTO and acting as agent for the HTF owners, may include the HTF Annual Transmission revenue Requirements (i.e., HTF Transmission Plant) within the Attachment F calculations. Additionally, the total HTF Annual Transmission Revenue Requirements included shall be limited to the following:

Year 1: A maximum of $1.2M in Year 1. For the sole purpose of this Schedule, "Year 1" shall be defined as the first full year after the Operations Date:

Year 2: A maximum of $2.0M in Year 2. For the sole purpose of this Schedule, "Year 2" shall be defined as the second full year after the Operations Date;

Year 3: A maximum of $2.8M in Year 3. For the sole purpose of this Schedule, "Year 3" shall be defined as the third full year after the Operations Date;

Year 4: A maximum of $3.5M in Year 4. For the sole purpose of this Schedule, "Year 4" shall be defined as the fourth full year after the Operations Date;

and

Year 5 and thereafter: All HTF Annual Transmission Revenue Requirements shall be included in Attachment F.

ATTACHMENT F IMPLEMENTATION RULE
APPENDIX C

I. DEFINITIONS

(i) **Annual True-up – Pre-1997 (ATU):** shall be the difference between the actual Pre-1997 Annual Transmission Revenue Requirements and the as-billed Pre-1997 Annual Transmission Revenue Requirements, adjusted to include interest pursuant to Part II below. The actual Pre-1997 Annual Transmission Revenue Requirements shall be an after-the-fact calculation and shall be determined at the conclusion of each rate-effective period, i.e. June 1 through May 31 of each year, by application of the Attachment F formula rate and each PTO's relevant Pre-1997 PTF cost data for the most recently concluded calendar year. The as-billed Pre-1997 Annual Transmission Revenue Requirements shall be those Pre-1997 Annual Transmission Revenue Requirements used to establish the RNS rates that were made effective on June 1 of the most recently concluded calendar year.

(ii) **Annual True-up – Post-1996 (ATU'):** shall be the difference between the actual Post-1996 Annual Transmission Revenue Requirements and the as-billed Post-1996 Annual Transmission Revenue Requirements, adjusted to include interest pursuant to Part II below. The actual Post-1996 Annual Transmission Revenue Requirements shall be an after-the-fact calculation and shall be determined at the conclusion of each rate-effective period, i.e. June 1 through May 31 of each year, by application of the Attachment F formula rate and each PTO's relevant Post-1996 PTF cost data for the most recently concluded calendar year.The as-billed Post-1996 Annual Transmission Revenue Requirements shall be those Post-1996 Annual Transmission Revenue Requirements used to establish the RNS rates that were made effective on June 1 of the most recently concluded calendar year and which included the sum of the Post-1996 Transmission Revenue Requirements for the year prior to the most recently concluded calendar year plus the Forecasted Transmission Revenue Requirements for the most recently concluded calendar year.

(iii) Forecast Period: The calendar year immediately following the calendar year for which the most recent FERC Form 1 data is available.

(iv) Forecasted Transmission Plant Additions (FTPA): shall equal an estimate of the PTO's Post-1996 PTF plant additions for the Forecast Period.

(v) Forecasted MPRP CWIP (FCWIP): shall equal CMP's estimated incremental change in MPRPCWIP for the Forecast Period.

(vi) Carrying Charge Factor (CCF): shall reflect the most recent calendar year data used in determining Post-1996 Annual Transmission Revenue Requirements and shall equal the sum of Attachment F Sections II.A, excluding MPRP CWIP and NEEWS CWIP, through II.H divided by Attachment F Section II.A.1.a.

(vii) MPRP Cost of Capital Rate (MCOC): shall be determined in accordance with Attachment F Section II.A.2.

(viii) Forecasted Transmission Revenue Requirement (FTRR): shall equal FTPA multiplied by the CCF plus FCWIP multiplied by the MCOC, plus FCCWIP multiplied by CCOC, plus FWCWIP multiplied by WCOC, plus FNCWIP multiplied by NCOC, as shown:

FTRR = FTPA * CCF + (FCWIP * MCOC) + (FCCWIP * CCOC) + (FWCWIP * WCOC) + (FNCWIP * NCOC)

(ix) Forecasted CL&P NEEWS CWIP (FCCWIP): shall equal CL&P's estimated incremental change in NEEWS CWIP for the Forecast Period.

(x) Forecasted WMECO NEEWS CWIP (FWCWIP): shall equal WMECO's estimated incremental change in NEEWS CWIP for the Forecast Period.

(xi) NEEWS CL&P Cost of Capital Rate (CCOC): shall be determined in accordance with Attachment F Section II.A.2.

(xii) NEEWS WMECO Cost of Capital Rate (WCOC): shall be determined in accordance with Attachment F Section II.A.2.

(xiii) Forecasted NEP NEEWS CWIP (FNCWIP): shall equal NEP's estimated incremental change in NEEWS CWIP for the Forecast Period.

(xiv) <u>NEEWS NEP Cost of Capital Rate (NCOC)</u>: shall be determined in accordance with Attachment F Section II.A.2.

II. INTEREST ON ANNUAL TRUE-UPS

Interest on the Annual True-up amounts (i.e., interest applicable to any over or under collection) shall be calculated in accordance with the methodology specified in the Commission’s regulations at 18 C.F.R. § 35.19a (a) (2) (iii).

III. INFORMATIONAL FILINGS

The PTOs’ annual informational filing shall include supporting documentation for their estimated capital additions to be placed in service during the current calendar year as well as supporting documentation pertaining to any annual true-up and interest calculations.

SCHEDULE 1

SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE

Scheduling, System Control and Dispatch Service is the service required to schedule at the regional level the movement of power through, out of, within, or into the New England Control Area. Local level service is provided by the PTOs under Schedule 21 to this OATT. For transmission service under this OATT, this Ancillary Service can be provided only by the ISO and the Transmission Customer must purchase this service from the ISO. Charges for Scheduling, System Control and Dispatch Service are to be based on the expenses incurred by the ISO, and by the individual PTOs in the operation of Local Control Center dispatch centers or otherwise, to provide these services. The expenses incurred by the ISO in providing these services recovered under Section IV of the OATT. A surcharge for the expenses incurred by PTOs in the provision of these services for transmission service over the PTF will be added to the Through or Out Service rate and to the Regional Network Service rate. Any Scheduling, System Control and Dispatch Service expenses for the provisions of these services for MTF Service shall be determined separately and assessed to Transmission Customers receiving MTF Service, in accordance with the arrangements between the Transmission Customers receiving MTF Service and the MTF Provider.

The expenses incurred in providing Scheduling, System Control and Dispatch Service for transmission service over the PTF for each PTO will be determined by an annual calculation based on the previous calendar year's data as shown, in the case of PTOs which are subject to the Commission's jurisdiction, in the PTO's FERC Form 1 report for that year, and shall be based on actual data in lieu of allocated data if specifically identified in the Form 1 report. The surcharge shall be redetermined annually as of June 1 in each year and shall be in effect for the succeeding twelve (12) months. The rate surcharge per kilowatt for each month is one-twelfth of the amount derived by dividing the total annual PTO expenses for providing the service by the sum of the average of the coincident Monthly Peaks (as defined in Section II.21.2) of all Local Networks for the prior calendar year.

Each Transmission Customer which is obligated to pay the rate for Regional Network Service for a month shall pay the surcharge on the basis of the number of kilowatts of its Monthly Network Load (as defined in Section II.21.2 of this OATT) for the month. Each Transmission Customer which is obligated to pay the rate for Through or Out Service for the applicable period shall pay the surcharge on the basis of the highest amount of its Reserved Capacity for each transaction scheduled as Through or Out Service for such period.

The details for implementation of Schedule 1 for transmission service over the PTF shall be established in accordance with the Implementation Rule for Schedule 1 attached to this OATT.

SCHEDULE 1 IMPLEMENTATION RULE

This rule provides detail with respect to the calculation of the rate surcharge each year for Scheduling, System Control and Dispatch Service, which is defined in the OATT as the service required to schedule the movement of power through, out of, within, or into the New England Control Area over Pool Transmission Facilities ("PTF"). This service also includes the dispatch and security analysis of the system. Scheduling, System Control and Dispatch Service for transmission service over transmission facilities other than PTF is provided under Schedule 21 of the OATT. For transmission service under the OATT, this Ancillary Service will be provided by the ISO, and rates collected under Schedule 1 are based on expenses incurred by the Local Control Centers, and the PTOs (as described herein) in providing the necessary elements of this service to the ISO. All of the costs of the ISO for the provision of service under Schedule 1 will be recovered under Section IV of the Transmission, Markets and Services Tariff. Schedule 1 of the OATT is for collection only of the revenue requirements for Local Control Centers and PTOs for System Control and Dispatch Service. Any Transmission Customer taking Regional Network Service or Through or Out Service shall be subject to the rate surcharge calculated under Schedule 1 of the OATT as described in more detail in this rule below.

The PTOs shall make an annual informational filing on or before July 31 of each year showing the Schedule 1 rate surcharge to be utilized by the ISO in the billing of Schedule 1 Ancillary Service that will be in effect for the period beginning June 1 of that year through May 31 of the subsequent year. If there are any corrections made to the information reflected in the informational filing after it has been submitted, the PTOs would file corrections to the informational filing. At least thirty (30) days before the informational filing is made with the Commission, the PTOs shall make available to Transmission Customers and any other interested parties a draft of the proposed filing for review and comment prior to the filing by posting such draft on the RTO NE website. The filing of the informational filing does not reopen the formula rate set forth below for review, but rather is contestable only with respect to the accuracy of the information contained in the informational filing. The ISO shall have the discretion to conduct audits of such charges, with advisory Stakeholder input on the scope of audit, including on any agreed-upon procedures to be used by the auditor. In this provision, the term "agreed-upon procedures" shall have the meaning afforded to it by the American Institute of Certified Public Accountants.

I. DEFINITIONS

Capitalized terms used in this rule that are not defined in the Tariff have the following definitions:

Scheduling and Dispatch Surcharge Rate shall equal the rate surcharge that is determined for the applicable period beginning on June 1, 1999, in accordance with Section II of this rule below.

PTF Transmission-Related Local Control Center Scheduling and Dispatch Expense shall equal the PTF transmission related expenses incurred by the PTO from REMVEC II, CONVEX/ESCC, and the Maine Local Control Center as recorded in each PTO's FERC Form 1, Account Nos. 561-561.4, excluding any charges recorded in this account that were incurred under the OATT or Schedule 21 of the OATT. The expenses shall be net of any revenues, as reflected in FERC Account No. 456, received by the PTO for providing scheduling and dispatch services, excluding any revenues recorded in this account that where received as a result of charges under the OATT.

REMVEC II is a Local Control Center of the ISO providing security analysis of PTF.

Local PTF Transmission-Related Scheduling and Dispatch Expense shall equal the sum of (1) each PTO's expenses as recorded in FERC Account Nos. 561-561.4, excluding any ISO and Local Control Center related expenses and any expenses recorded in these accounts, that were incurred under this OATT or the Schedule 21 of this OATT of each PTO as a Transmission Customer, multiplied by the PTF Transmission Plant Allocator, (2) NSTAR Electric Company SCADA-related expenses as calculated in accordance with Appendix A of this Rule, (3) the Central Maine Power Company Local Control Center revenue requirements as calculated in accordance with Appendix B of this Rule, and (4) the CL&P Dispatch Center Revenue Requirement as calculated in accordance with Appendix C of the Rule.

PTF Transmission Plant Allocation Factor is the factor for allocating transmission costs and expenses between PTF and Non-PTF as determined for the applicable period pursuant to Attachment F of the OATT.

II. CALCULATION OF THE SCHEDULING AND DISPATCH SURCHARGE

A. Surcharge for Regional Network Service Customers

For Network Customers, the scheduling and dispatch surcharge for Regional Network Service shall equal the Network Customer's Regional Monthly Network Load, as defined in Section II.21.2 of the OATT,

multiplied by the Monthly Scheduling and Dispatch Surcharge Rate as determined in accordance with Section II.C below.

B. Surcharge for Through or Out Customers

For Through or Out Service Customers, the Scheduling and Dispatch Surcharge shall equal the Transmission Customer's Reserved Capacity for each transaction scheduled for the month multiplied by the applicable Monthly or Hourly Scheduling and Dispatch Surcharge Rate, as determined in accordance with Section II.C below.

C. Scheduling and Dispatch Surcharge Rate

The Scheduling and Dispatch Surcharge Rate will be the surcharge rate in effect from time to time for the applicable period, determined pursuant to the formula described below based on the prior calendar year's data. The Scheduling and Dispatch Surcharge Rate shall be redetermined each year, with the new Surcharge Rate going into effect on June 1 of each year, and be effective for the succeeding twelve months.

In the case of PTOs which are subject to the Commission's jurisdiction, the data used shall be as identified in the PTO's FERC Form 1 report for that year, and shall be based on actual data in lieu of allocated data if specifically identified in the FERC Form 1. When FERC Form 1 data is not the direct source of the data used in the formula, the worksheets used to develop the inputs will reflect Appendix A, Appendix B, and Appendix C of this Rule.

The Scheduling and Dispatch Surcharge Rate shall be equal to the sum of (1) PTF Transmission-Related Local Control Center Scheduling and Dispatch Expense, (2) Local PTF Transmission Related Scheduling and Dispatch Expense, (3) less Schedule 1 revenues from the prior year surcharges for Short-Term Point-To-Point Transactions, and divided by the annual average of the sum of all Regional Network Customers Monthly Peak Load, as defined in Section II.21.2 of the OATT, from the prior calendar year plus the Long-Term Firm Point-To-Point Service Reserved Capacity, from the prior calendar year.

The Monthly Scheduling and Dispatch Surcharge Rate shall equal one-twelfth of the Scheduling and Dispatch Surcharge Rate.

The Hourly Scheduling and Dispatch Surcharge Rate shall be the annual rate divided by 8760.

APPENDIX A TO SCHEDULE 1 IMPLEMENTATION RULE

NSTAR ELECTRIC COMPANY SCADA

This service is required to schedule the movement of power through, out of, within, or into the New England Control Area over Pool Transmission Facilities (PTF). Service under this schedule represents the contribution to that service provided by the PTO's own Dispatch Center, commonly referred to as SCADA. These costs are excluded from costs in Attachment F.

The PTF Revenue Requirement for the scheduling, system control and dispatch service that is based on data for the calendar year 2004 or later shall include an allocated PTF-related amount of Incremental Return and Associated Income Taxes on SCADA-related transmission plant investments included in the Regional System Plan and placed in-service on or after January 1, 2004 (such investments referred to herein as "Post-2003 Dispatch Center Investment"). The Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment shall reflect a surcharge of a 100 basis point ROE adder applicable to certain investment base components as specified in the formula below. The data used in determining the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment shall be based on actual data in lieu of allocated data if specifically identified in NSTAR Electric's accounting records.

Definitions: Dispatch Center Wages and Salaries Allocation Factor: Ratio of Dispatch Center Related Direct Wages and Salaries to NSTAR Electric's total Direct Wages and Salaries excluding Administrative and General Wages and Salaries.

Dispatch Center Plant Allocation Factor: Ratio of Total Investment in Dispatch Center Plant plus Dispatch Center Related General Plant, to Total Plant in service.

Dispatch Center Transmission Plant Allocation Factor: Ratio of Total Investment in Dispatch Center Plant plus Dispatch Center Related General Plant, to Total Investment in Transmission Plant.

The PTF Revenue Requirement for the Scheduling System Control and Dispatch Service shall equal the sum of the PTO's: (A) Return and Associated Income Taxes (including the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment), (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Related Amortization of Investment Tax Credits, (D) Dispatch Center

Related Municipal Tax Expense, (E) Dispatch Center Related Payroll Tax Expense (F) Dispatch Center Operation and Maintenance Expense, and (G) Dispatch Center Related Administrative and General Expense; multiplied by the PTF Transmission Plant Allocation Factor.

The Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment shall be calculated using the Dispatch Center investment base components specifically identified in Section A.1 of the formula below.

A. <u>Return and Associated Income Taxes</u> shall equal the product of the Dispatch Center Investment Base and the Cost of Capital Rate. To calculate the Incremental Return and Associated Income Taxes for Post–2003 Dispatch Center Investment, the Dispatch Center Investment Base will only include items (a), (d) and (e) under Section (A)(1), calculated in the manner indicated.

1. **<u>The Dispatch Center Investment Base</u>** will consist of (a) Dispatch Center Plant in FERC accounts 350-359, plus (b) Dispatch Center Related General Plant, plus (c) Dispatch Center Plant Held for Future Use, less (d) Dispatch Center Related Depreciation Reserve, less (e) Dispatch Center Related Accumulated Deferred Taxes, plus (f) Other Regulatory Assets, plus (g) Dispatch Center Prepayments, plus (h) Dispatch Center Materials and Supplies, plus (i) Dispatch Center Related Cash Working Capital.

a. <u>Dispatch Center Plant</u> will equal the year-end balance of the PTO's Investment in Dispatch Center per FERC accounts 350 through 359. Dispatch Center Plant Investment is not included in PTF investment in the Attachment F revenue requirement. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, Post-2003 Dispatch Center Plant shall be separately identified.

b. <u>Dispatch Center Related General Plant</u> shall equal the PTO's year-end balance of Investment in General Plant multiplied by the Dispatch Center Wages and Salaries Allocation Factor described above.

c. <u>Dispatch Center Plant Held for Future Use</u> shall equal the year-end balance of Transmission related Dispatch Center Investment in FERC account 105.

d. <u>Dispatch Center Related Depreciation Reserve</u> shall equal the year-end balance of Transmission Dispatch Center Depreciation Reserve, plus the year-end balance of

Dispatch Center Related General Depreciation Reserve. Dispatch Center Related General Plant Depreciation Reserve shall equal the product of General Plant Depreciation Reserve and the Dispatch Center Wages and Salaries Allocation Factor described above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, Dispatch Center Depreciation Reserve associated with the Post-2003 Dispatch Center Investment, shall equal the balance of the Dispatch Center Depreciation Reserve multiplied by the ratio of Post-2003 Dispatch Center Plant to total investment in Dispatch Center Plant.

e. Dispatch Center Related Accumulated Deferred Taxes shall equal the year-end balance of Total Accumulated Deferred Income Taxes, multiplied by the Dispatch Center Plant Allocation Factor described above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, Total Accumulated Deferred Income Taxes associated with the Post-2003 Dispatch Center Investment, shall equal the balance of total property-related accumulated deferred income taxes as recorded in FERC Accounts 281 and 282, multiplied by the Dispatch Center Plant Allocation Factor, further multiplied by the ratio of the Post-2003 Dispatch Center Plant to total investment in Dispatch Center Plant.

f. Other Regulatory Assets shall equal the year-end balance of FAS 106 multiplied by the Dispatch Center Wages and Salaries Allocation Factor described in Section (A) (2) (b) above and the year-end balance of FAS 109, net of FAS 109 liability, multiplied by the Dispatch Center Plant Allocation Factor described in above.

g. Dispatch Center Prepayments shall equal the year-end balance of Prepayments multiplied by the Dispatch Center Wages and Salaries Allocation Factor described above.

h. Dispatch Center Materials and Supplies shall equal the year-end balance of Transmission Plant Materials and Supplies multiplied times the Dispatch Center Plant Allocation Factor described above.

i. Dispatch Center Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Dispatch Center Transmission Related Operation and Maintenance Expense and Dispatch Center Transmission Related Administrative and General Expense.

2. The Cost of Capital Rate shall equal (a) the Weighted Cost of Capital, plus (b) Federal Income Taxes, plus (c) State Income Taxes.

a. the Weighted Cost of Capital will be calculated based upon the PTO's capital structure at the end of each year and will equal the sum of (i), (ii) and (iii) below.

The Cost of Capital Rate to be used in calculating the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, shall only reflect item (iii) below and shall apply in the manner indicated below.

i. the Long Term Debt Component, which equals the product of the actual weighted average embedded cost to maturity of Long Term Debt then outstanding and the ratio that Long-Term Debt is to Total Capital.

ii. the Preferred Stock Component, which equals the product of the actual weighted average embedded cost to maturity of Preferred Stock then outstanding and the ratio that Preferred Stock is to Total Capital.

iii. the Return on Equity Component, which equals the product of the PTO's Return on Equity as set in the PTO's RNS open access rate and the ratio that Common Equity is to Total Capital. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, the incremental return on equity shall be the product of 1.00% and the ratio of Common Equity to Total Capital.

b. Federal Income Taxes shall equal

$$\frac{A + [(C+B)/D]) \times FT}{1 - FT}$$

Where FT is the Federal Income Tax Rate and A is the sum of the Preferred Stock Component and the Return on Equity Component, as determined in Sections A.2.(a)(ii) and (iii) above, B is Dispatch Center Related Amortization of Investment Tax Credits, as determined in Section II.D. below, C is the Equity AFUDC component of Dispatch Center Depreciation Expense, as defined in

Section B., and D is Dispatch Center Investment Base, as determined in A.1., above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, the incremental Federal Income Tax shall equal:

$$(A'*FT)/(1-FT)$$

Where FT is the Federal Income Tax Rate and A' is the incremental return on equity component, as determined in Section A.2.(a)(iii) above.

c. <u>State Income Taxes shall equal</u>

$$\frac{(A + [(C+B)/D] + \text{Federal Income Tax}) \times ST}{1 - ST}$$

Where ST is the State Income Tax Rate and A is the sum of the Preferred Stock Component and the Return on Equity Component, as determined in Section A.2.(a)(ii), and Section A.2.(a)(iii) above, and Federal Income Tax is the rate determined in Section A.2.(b) above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, the incremental State Income Tax shall equal:

$$(A' + \text{Federal Income Tax})*ST/(1-ST)$$

Where ST is the State Income Tax Rate and A' is the incremental return on equity component, as determined in Section A.2.(a)(iii) above, and Federal Income Tax is the rate determined in Section A.2.(b) above.

B. <u>Dispatch Center Depreciation Expense</u> shall equal the sum of Transmission Depreciation Expense for Dispatch Center Plant, plus an allocation of General Plant Depreciation Expense calculated by multiplying General Plant Depreciation Expense by the Dispatch Center Wages and Salaries Allocation Factor, described in Section (A)(1)(b) above.

C. <u>Dispatch Center Related Amortization of Investment Tax Credits</u> shall equal the PTO's Amortization of Investment Tax Credits multiplied by the Dispatch Center Plant Allocation Factor described above.

D. Dispatch Center Related Municipal Tax Expense shall equal the PTO's total Municipal Tax Expense multiplied by the Dispatch Center Plant Allocation Factor described above.

E. Dispatch Center Related Payroll Tax Expense shall equal the PTO's total electric payroll tax expense, multiplied by the Dispatch Center Wages and Salaries Allocation Factor, described above.

F. Dispatch Center Operation and Maintenance Expense shall equal all expenses related to SCADA operation charged to FERC Account Number 561 through 561.4, excluding any ISO and Local Control Center related expenses and any expenses recorded in this Account that were incurred under this OATT or the Local Service Schedules of this OATT as a Transmission Customer.

G. Dispatch Center Related Administrative and General Expenses shall equal the sum of (1) PTO's Administrative and General Expenses multiplied by the Dispatch Center Wages and Salaries Allocation Factor, (2) Property Insurance multiplied by the Dispatch Center Plant Allocation Factor, and (3) Expenses included in Account 928 (excluding Merger-Related Costs included in Account 928) related to FERC Assessments multiplied by Dispatch Center Plant Allocation Factor, plus any other Federal and State Dispatch Center related expenses or assessments, plus specific Dispatch Center related expenses included in Account 930.1 plus Transmission Merger-Related Costs multiplied by the Dispatch Center Transmission Plant Allocation Factor.

APPENDIX B TO SCHEDULE 1 IMPLEMENTATION RULE CENTRAL MAINE POWER COMPANY LOCAL CONTROL CENTER

I. **DEFINITIONS**

Capitalized terms not otherwise defined in the Tariff and as used in this rule have the following definitions:

A. ALLOCATION FACTORS

1. Wages and Salaries Allocation Factor shall equal the ratio of the Local Control Center Direct Wages and Salaries to total direct wages and salaries excluding administrative and general wages and salaries.

2. Local Control Center Wages and Salaries Allocation Factor shall equal the ratio of the Transmission Local Control Center Direct Wages and Salaries to total Local Control Center Direct Wages and Salaries.

3. Local Control Center PTF Allocation Factor shall equal the ratio of the Local Control Center PTF Direct Wages and Salaries to the total Local Control Center Transmission Direct Wages and Salaries.

4. Local Control Center Plant Allocation Factor shall equal the ratio of the Total Investment in Local Control Center Plant to Total Plant in service.

B. TERMS

Administrative and General Expense shall equal the PTO's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928, and 930.1.

Amortization of Investment Tax Credits shall equal the PTO's credits as recorded in FERC Account No. 411.4

Amortization of Loss on Reacquired Debt shall equal the PTO's expenses as recorded in FERC Account No. 428.1

Other Regulatory Assets/Liabilities -FAS 106 shall equal the net of the PTO's FAS 106 balance as recorded in FERC Account 182.3 and any FAS 106 balance as recorded in the PTO's FERC Account No. 254.

Other Regulatory Assets/Liabilities -FAS 109 shall equal the net of the PTO's FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in the PTO's FERC Account No. 254.

Payroll Taxes shall equal those payroll expenses as recorded in the PTO's FERC Account Nos. 408.1 and 409.1.

Plant Held for Future Use shall equal the PTO's balance in FERC Account No. 105.

Prepayments shall equal the PTO's prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal the PTO's expenses as recorded in FERC Account No. 924.

PTF Local Control Center Direct Wages and Salaries shall equal the PTO's direct wages and salaries related to providing PTF Local Control Center services as recorded in FERC Account No. 561.

Local Control Center Direct Wages and Salaries shall equal the PTO's direct wages and salaries related to providing Local Control Center services as recorded in FERC Account Nos. 556, 561-561.4, and 581.

Local Control Center Operation and Maintenance Expense shall equal the PTO's expenses recorded in FERC Account Nos. 556, 561-561.4, & 581, less any costs included in FERC Account Nos. 561-561.4 that are otherwise recoverable pursuant to Subpart (1) of the Local PTF Transmission Related Scheduling and Dispatch Expense of the rule implementing the Schedule 1 rate surcharge of the OATT.

Local Control Center Plant Depreciation Reserve shall equal the PTO's depreciation reserve balance for Local Control Center Related Plant as recorded in FERC Account No. 108.

<u>Materials and Supplies</u> shall equal the PTO's balance as recorded in FERC Account No. 154.

<u>Local Control Center Related Depreciation Expense</u> shall equal the PTO's depreciation expense for Local Control Center Related Plant as recorded in FERC Account No. 403.

<u>Local Control Center Related Plant</u> shall equal the PTO's gross plant balances used for system control and dispatch purposes as recorded in FERC Account Nos. 303-399. To the extent that such plant includes any amounts recorded as transmission investment in FERC Account Nos. 350-359, such amounts will be excluded for purposes of determining annual transmission revenue requirements pursuant to the billing rule which implements Attachment F of the OATT.

<u>Local Control Center Support Revenues</u> shall equal the revenues received from Local Control Center supporters as recorded in FERC Account Nos. 454 and 456, excluding any revenues received under Schedule 1 of the OATT or the PTO's Local Service Schedule.

<u>Total Accumulated Deferred Income Taxes</u> shall equal the net of the deferred tax balances as recorded in FERC Account Nos. 281-283 and 190.

<u>Total Loss on Reacquired Debt</u> shall equal the PTO's balance as recorded in FERC Account No. 189.

<u>Total Municipal Tax Expense</u> shall equal the PTO's municipal tax expenses as recorded in FERC Account Nos. 408.1 and 409.1.

<u>Total Plant in Service</u> shall equal the PTO's total gross plant balance as recorded in FERC Account Nos. 301-399.

<u>Transmission Local Control Center Direct Wages and Salaries</u> shall equal the PTO's direct wages and salaries related to providing Local Control Center services as recorded in FERC Account No. 561-561.4.

II. CALCULATION OF TOTAL LOCAL CONTROL CENTER REVENUE REQUIREMENTS

The Local Control Center Revenue Requirements based on data for calendar year 2004 or later shall include an Incremental Return and Associated Income Taxes on Central Maine's local control center investments

included in the Regional System Plan and placed in service on or after January 1, 2004 (such investments referred to herein as "Post-2003 Investment"). The Incremental Return and Associated Income Taxes for Post-2003 Investment shall reflect a surcharge of a 100 basis point ROE adder applicable to certain investment base components as specified in the formula below. The data used in determining the Incremental Return and Associated Income Taxes for Post-2003 Investment shall be based on actual data in lieu of allocated data if specifically identified in Central Maine's accounting records.

The Local Control Center Revenue Requirement shall equal the sum of the Local Control Center related (A) Return and Associated Income Taxes (including the Incremental Return and Associated Income Taxes for Post-2003 Investment), (B) Depreciation Expense, (C) Amortization of Loss on Reacquired Debt, (D) Amortization of Investment Tax Credits, (E) Municipal Tax Expense, (F) Payroll Tax Expense, (G) Operations and Maintenance Expense, (H) Administrative and General, minus (I) Support Revenues.

The Incremental Return and Associated Income Taxes for Post-2003 Investment shall be calculated using the investment base components specifically identified in Section A.1. of the formula below.

A. <u>Return and Associated Income Taxes</u> shall equal the product of the Local Control Center Investment Base and the Cost of Capital Rate reflected in the PTO's Attachment F formula of the OATT. To calculate the Incremental Return and Associated Income Taxes for Post 2003 Investment, Local Control Center Investment Base shall only include Sections II.A.1.(a), (b), and (c), in the manner indicated.

1. <u>Local Control Center Investment Base</u>

The Local Control Center Investment Base will be the year end balances of Local Control Center related: (a) Plant, plus (b) Plant Held for Future Use, less (c) Depreciation Reserve, less (d) Accumulated Deferred Taxes, plus (e) Loss on Reacquired Debt, plus (f) Other Regulatory Assets/Liabilities, plus (g) prepayments, plus (h) Materials and Supplies, plus (i) Cash Working Capital.

(a) <u>Local Control Center Related Plant</u> shall equal the balance of the PTO's Investment in Local Control Center Plant. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Investment, Post 2003 Local Control Center Plant shall be separately identified.

(b) Local Control Center Related Plant Held for Future Use shall equal the balance of Plant Held for Future Use multiplied by the Local Control Center Plant Allocation Factor.

(c) Local Control Center Related Depreciation Reserve shall equal the Depreciation Reserve for the PTO's investment in Local Control Center plant. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Investment, Local Control Center Depreciation Reserve shall equal the Depreciation Reserve for the PTO's Local Control Center Plant identified in (a) above.

(d) Local Control Center Related Accumulated Deferred Taxes shall equal the PTO's electric balance of Accumulated Deferred Income Taxes multiplied by the Local Control Center Plant Allocation Factor. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Investment, Local Control Center Accumulated Deferred Taxes shall equal the PTO's balance of total property related accumulated deferred income taxes recorded in FERC account 281and 282 multiplied by the Local Control Center Plant Allocation Factor and further multiplied by the ratio of Post-2003 Investment to Total Local Control Center Related Plant.

(e) Local Control Center Related Loss on Reacquired Debt shall equal the PTO's electric balance of Total Loss on Reacquired Debt multiplied by the Local Control Center Plant Allocation Factor.

(f) Local Control Center Related Other Regulatory Assets/Liabilities shall equal the PTO's electric balance of any deferred recovery of FAS 106 expenses multiplied by the Local Control Center Wages and Salaries Allocation Factor, plus the PTO's electric balance of FAS 109 multiplied by the Local Control Center Plant Allocation Factor.

(g) Local Control Center Related Prepayments shall equal the PTO's electric balance of prepayments multiplied by the Local Control Center Plant Allocation Factor.

(h) Local Control Center Related Materials and Supplies shall equal the PTO's electric balance of Plant Materials and Supplies, multiplied by the Local Control Center Plant Allocation Factor.

(i) Local Control Center Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Local Control Center Operation and Maintenance Expense, Local Control Center Related Administrative and General Expense.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) the PTO's Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon the capital structure at the end of each year and will equal the sum of (i),(ii), and (iii) below. The Cost of Capital Rate to be used in calculating the Incremental Return and Associated Income Taxes for Post-2003 Investment shall only reflect item (iii) below and shall apply in the manner indicated below

(b) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity of the PTO's long-term debt then outstanding and the ratio that long-term debt is to the PTO's total capital.

(c) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of the PTO's preferred stock then outstanding and the ratio that preferred stock is to the PTO's total capital.

(d) the return on equity component, which equals the product of the PTO's Return on Equity as set in the PTO's RNS open access rate and the ratio that common equity is to the PTO's total capital. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Investment, the incremental return on equity shall be the product of Central Maine's incremental return on equity of 1.0% and the ratio that common equity is to the PTO's total capital.

(e) Federal Income Tax shall equal

$$\frac{(A+[(C+B)/D]) \times FT}{1 - FT}$$

Where FT is the Federal Income Tax Rate and A is the sum of the preferred stock component and the return on equity component, as determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section II.D. below, C is the equity AFUDC component of Local Control Center Depreciation Expense, as defined in II.B., and D is Local Control Center Investment Base, as determined in II.A.1., above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Investment, the incremental Federal Income Tax shall equal

$$\frac{(A' * FT)}{(1 - FT)}$$

where FT is the Federal Income Tax Rate and A' is the incremental return on equity component, as determined in Section II.A.2.(a)(iii) above.

(f) <u>State Income Tax</u> shall equal

$$\frac{(A+[(C+B)/D] + \text{Federal Income Tax}) \times ST}{1 - ST}$$

Where ST is the State Income Tax Rate, A is the sum of the preferred stock component and return on equity component determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section II.D. below, C is the equity AFUDC component of Local Control Center Depreciation Expense, as defined in II.B., D is the Local Control Center Investment Base, as determined in II.A.1., above and Federal Income Tax is the rate determined in Section II.A.1.(b) above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Investment, the incremental State Income Tax shall equal

$$\frac{(A' + \text{Federal Income Tax})(ST)}{(1 - ST)}$$

where ST is the State Income Tax Rate, A' is the incremental return on equity component determined in Section II.A.2.(a)(iii) above, and Federal Income Tax is the rate determined in Section II.A.2.(b) above.

B. <u>Local Control Center Depreciation Expense</u> shall equal the Local Control Center Plant Depreciation Expense and Accumulated Amortization.

C. Local Control Center Related Amortization of Loss on Reacquired Debt shall equal the PTO's electric balance of Loss on Reacquired Debt multiplied by the Local Control Center Plant Allocation Factor.

D. Local Control Center Related Amortization of Investment Tax Credits shall equal the PTO's electric Amortization of Investment Tax Credits multiplied by the Local Control Center Plant Allocation Factor.

E. Local Control Center Related Municipal Tax Expense shall equal the PTO's total electric municipal tax expense multiplied by the Local Control Center Plant Allocation Factor.

F. Local Control Center Related Payroll Tax Expense shall equal the PTO's total electric payroll tax expense, multiplied by the Wages and Salaries Allocation Factor.

G. Local Control Center Operation and Maintenance Expense shall equal the PTO's Operation and Maintenance Expenses recorded in FERC Account Nos. 556, 561-561.4, and 581, less any costs included in FERC Account Nos. 561-561.4 that are otherwise recoverable pursuant to Subpart (1) of Local PTF Transmission Related Scheduling and Dispatch Expense of the rule implementing the Schedule 1 rate surcharge of the OATT.

H. Local Control Center Related Administrative and General Expenses shall equal the sum of (1) PTO's Administrative and General Expenses multiplied by the Wages and Salaries Allocation Factor, (2) Property Insurance multiplied by the Local Control Center Plant Allocation Factor, and (3) Expenses included in Account 928 related to FERC Assessments multiplied by the Local Control Center Plant Allocation Factor, plus any other Federal and State Local Control Center related expenses or assessments, plus specific Local Control Center related expenses included in Account 930.1.

I. Transmission Support Revenues shall equal the PTO's revenue received for providing system control and dispatch service.

III. CALCULATION OF LOCAL CONTROL CENTER TRANSMISSION REVENUE REQUIREMENTS

The Total Local Control Center Revenue Requirements derived in Section II. above are further multiplied by the Local Control Center Wages and Salaries Allocation Factor defined in Section I. A. 2. above to determine the transmission related revenue requirement, and further multiplied by the Local Control Center PTF Allocation Factor defined in Section I. A. 3. above, to determine the PTF Transmission related revenue requirements to be included in Schedule I of the OATT.

APPENDIX C TO SCHEDULE 1 IMPLEMENTATION RULE
CL&P DISPATCH CENTER REVENUE REQUIREMENT

This appendix calculates the CL&P Dispatch Center Revenue Requirement for use in calculating part (4) of the Local PTF Transmission-Related Scheduling and Dispatch expenses in the Schedule 1 Implementation Rule. The CL&P Dispatch Center Revenue Requirement for use during a calendar year shall be based on CL&P's costs for the immediately preceding calendar year.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section II.1 of the OATT and as used in this appendix have the following definitions:

Dispatch Center means CL&P's CONVEX dispatch center.

Dispatch Center Plant shall equal CL&P's year-end gross plant balances used for CL&P's Dispatch Center as recorded in FERC Account Nos. 303, 350-359, and 389-399.

Dispatch Center Depreciation Reserve shall equal CL&P's year-end depreciation reserve balance for Dispatch Center Plant as recorded in FERC Account No. 108. Dispatch Center Accumulated Deferred Income Taxes shall equal the net of CL&P's year-end deferred tax balances for Dispatch center Plant as recorded in FERC Account Nos. 281-283 and 190.

II. CALCULATION OF TOTAL DISPATCH CENTER REVENUE REQUIREMENT

The Dispatch Center Revenue Requirement shall equal the sum of (A) Dispatch Center Return and Associated Income Taxes, (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Amortization of Investment Tax Credits, and (D) Dispatch Center Municipal Tax Expense; provided, that during the period June 1, 2008 through May 31, 2009, the Dispatch Center Revenue Requirement shall equal the product of (i) the number of months (or fractions thereof) remaining in 2007 on and after the date upon which the Convex Agreements are permitted to be made effective by FERC, divided by 12 and (ii) the sum of (A) Dispatch Center Return and Associated Income Taxes, (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Amortization of Investment Tax Credits, and (D) Dispatch Center Municipal Tax Expense. "CONVEX Agreements" refers to the agreements between The Connecticut Light & Power Company and

various entities relating to the operation of the Dispatch Center and filed with FERC contemporaneously with the filing of this Appendix C.

A. Dispatch Center Return and Associated Income Taxes shall equal the product of the Dispatch Center Investment Base and the Cost of Capital Rate.

1. Dispatch Center Investment Base

The Dispatch Center Investment Base will be the year-end balances of:

(a) Dispatch Center Plant, less (b) Dispatch Center Depreciation Reserve, less (c) Dispatch Center Accumulated Deferred Income Taxes.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) the Weighted Cost of Capital, plus (b) Federal Income Tax, plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon CL&P's capital structure at the end of each year and will equal the sum of (i), (ii), and (iii) below.

(i) The long-term debt component, which equals the product of the year-end balance of CL&P's first mortgage bonds and pollution control notes adjusted for premiums, discounts, debt expense and losses on reacquired debt and the ratio of the long term debt to CL&P's total capital.

(ii) The preferred stock component, which equals the product of the year-end balance of CL&P's preferred stock adjusted for premiums, discounts and unamortized issue expense and the ratio of the preferred stock to CL&P's total capital.

(iii) The common equity component, which equals the product of 10.3% and the ratio of the common equity to CL&P's total capital.

(b and c) Federal and State Income Taxes shall be computed as follows:

AxBxC

where: A = Dispatch Center Investment Base

B = Cost of equity capital (the sum of the preferred stock component and common equity component)

C = TC/(1-TE), where TE is the effective combined federal and state statutory income tax rates in effect at the applicable time.

B. Dispatch Center Depreciation Expense shall equal CL&P's Dispatch Center depreciation expense as recorded in FERC Account No. 403.

C. Dispatch Center Amortization of Investment Tax Credits shall equal CL&P's Dispatch Center amortization of investment tax credits as recorded in FERC Account No. 411.1.

D. Dispatch Center Municipal Tax Expense shall equal CL&P's Dispatch Center municipal tax expense as recorded in FERC Account Nos. 408.1 and 409.1.

SCHEDULE 21 - NSTAR

NSTAR ELECTRIC COMPANY

LOCAL SERVICE SCHEDULE

I COMMON SERVICE PROVISIONS

1.0 DEFINITIONS

Whenever used in this Local Service Schedule, in either the singular or plural number, the following capitalized terms shall have the meanings specified in this Section 1. Terms used in this Local Service Schedule that are not defined in this Local Service Schedule shall have the meanings set forth in the Tariff or customarily attributed to such terms by the electric utility industry in New England. Where there is a conflict between this Local Service Schedule and the Tariff, the terms here shall apply.

1.1 Annual Transmission Revenue Requirements

The total annual cost of the Transmission System shall be the amount specified in Attachment D until amended by NSTAR or modified by the Commission.

1.2 Annual True-Up

The reconciliation to actual costs of the estimated costs used for billing purposes under Section 4.0 of this Local Service Schedule for any Service Year.

1.3 Designated Agent

Any entity that performs actions or functions on behalf of NSTAR, an Eligible Customer, or the Transmission Customer required under the Local Service Schedule.

1.4 Firm Local Point-To-Point Service

Transmission service under this Local Service Schedule that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to this Local Service Schedule.

1.5 Load Ratio Share

Ratio of a Transmission Customer's most recently reported Monthly Network Load in the case of Network Customers and including, where applicable, the Reserved Capacity of Transmission Customers taking Firm Local Point-To-Point Service, to the total load of Network Customers and the Reserved Capacity of Transmission Customers taking Firm Local Point-To-Point Service.

1.6 Local Network

All transmission facilities constituting NSTAR's non-Pool Transmission Facilities (Non-PTF), excluding the Phase I/II HVDC-TF, which is defined in Schedule 20A of this OATT.

1.7 Local Network Load

The load that a Network Customer designates for Local Network Service under this Local Service Schedule. The Network Customer's Local Network Load shall include all load designated by the Network Customer, (including losses). A Network Customer may elect to designate less than its total load as Local Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete Points of Delivery as Local Network Load, the Eligible Customer is responsible for making separate arrangements under this Local Service Schedule for any Local Point-To-Point Service that may be necessary for such non-designated load.

1.8 Local Network Service

The transmission service provided under this Local Service Schedule over NSTAR's Local Network.

1.9 Local Network Upgrades

Modifications or additions to transmission-related facilities that are integrated with and support NSTAR's overall Transmission System for the general benefit of all users of such Transmission System.

1.10 Local Point-To-Point Service

The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under this Local Service Schedule over NSTAR's Local Network.

1.11 Long-Term Firm Local Point-To-Point Service

Firm Local Point-To-Point Service provided under this Local Service Schedule with a term of one year or more.

1.12 Monthly Network Load

A Network Customer's hourly load (including its designated Local Network Load not physically interconnected with NSTAR under Section 15.2 of this Local Service Schedule) coincident with NSTAR's Monthly Transmission System Peak.

1.13 Native Load Customers

The wholesale and retail power customers of NSTAR on whose behalf NSTAR, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate NSTAR's system to meet the reliable electric needs of such customers.

1.14 NERC

North American Electric Reliability Council, the Electric Reliability Organization of the United States.

1.15 Non-Firm Local Point-To-Point Service

Local Point-To-Point Service under this Local Service Schedule that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in this Local Service Schedule. Non-Firm Local Point-To-Point Service is available on a stand-alone basis for periods ranging from one hour to one month.

1.16 NPCC

Northeast Power Coordinating Council, a regional reliability council of NERC.

1.17 NSTAR

NSTAR Electric Company, a Massachusetts Corporation with offices located at 800 Boylston Street, Boston, Massachusetts 02199. NSTAR owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce and provides service pursuant to the rates, terms and conditions of this Local Service Schedule and the applicable terms and conditions of this Local Service Schedule.

1.18 NSTAR's Monthly Transmission System Load

NSTAR's Monthly Transmission System Peak minus the coincident peak usage of all Firm Local Point-To-Point Service customers pursuant to Part II of this Local Service Schedule plus the Reserved Capacity of all Firm Local Point-To-Point Service customers.

1.19 NSTAR's Monthly Transmission System Peak

The maximum firm usage of NSTAR's Transmission System in a calendar month.

1.20 Parties

NSTAR and the Transmission Customer receiving service under this Local Service Schedule.

1.21 Point(s) of Delivery

Point(s) on NSTAR's Transmission System where capacity and energy transmitted by NSTAR will be made available to the Receiving Party under this Local Service Schedule. The Point(s) of Delivery shall be specified in the Transmission Service Agreement.

1.22 Point(s) of Receipt

Point(s) of interconnection on NSTAR's Transmission System where capacity and energy will be made available to NSTAR by the Delivering Party under this Local Service Schedule. The Point(s) of Receipt shall be specified in the Transmission Service Agreement.

1.23 Service Year

The calendar year in which the Transmission Customer is receiving service under this Local Service Schedule.

1.24 Short-Term Firm Local Point-To-Point Service

Firm Local Point-To-Point Service under this Local Service Schedule with a term of less than one year.

1.25 Transmission System

The facilities owned, controlled or operated by NSTAR that are used to provide transmission service under this Local Service Schedule.

2.0 ANCILLARY SERVICES

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. NSTAR is required to provide and the Transmission Customer is required to purchase the following Ancillary Services (i) Scheduling, System Control and Dispatch, and (ii) Supplemental End-Use Reactive Support Service.

In addition, the Transmission Customer is required to purchase additional Ancillary Services under the terms and conditions of the Tariff. The Transmission Customer may not decline the Transmission Provider's offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it

will purchase from the Transmission Provider. A Transmission Customer that exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or an Eligible Customer that uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved is required to pay for all of the Ancillary Services identified in this section that were provided by the Transmission Provider associated with the unreserved service. The Transmission Customer or Eligible Customer will pay for Ancillary Services based on the amount of transmission service it used but did not reserve. NSTAR shall also assess a penalty for any unauthorized use of Ancillary Services by the Transmission Customer, based on the amount of transmission service it used but did not reserve, using the rate shown for such Ancillary Service.

The prices and/or compensation methods for Local System Control and Dispatch Services and Supplemental End-Use Reactive Support Service are described in Attachment D and Schedule 2, respectively, attached to and made a part of this Local Service Schedule. Three principal requirements apply to discounts for Ancillary Services provided by NSTAR in conjunction with its provision of transmission service as follows: (1) any offer of a discount made by NSTAR must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. A discount agreed upon for an Ancillary Service must be offered for the same period to all Eligible Customers on NSTAR's system.

3.0 CREDITWORTHINESS

NSTAR's creditworthiness procedures are specified in Attachment L to this Local Service Schedule.

4.0 BILLING AND PAYMENT

4.1 Billing Procedure

Within a reasonable time after the first day of each month, NSTAR shall submit an invoice to the Transmission Customer for the charges for all services furnished under this Local Service Schedule during the preceding month. The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to NSTAR, or by wire transfer to a bank named by NSTAR.

Billings hereunder shall be based on cost estimates made by NSTAR subject to Annual True-up

when actual costs for the Service Year are known. Such Annual True-up shall occur no later than six (6) months after the close of the Service Year to which the Annual True-up relates. To the extent bill adjustments are required pursuant to the Annual True-up, such adjustments shall bear interest calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii).

(i) The Annual True-Up shall be performed by recalculation of the costs for the Service Year based on actual cost and load information as reported in the FERC Form 1 for that Service Year and shall develop thereby an Embedded Cost Charge, defined in Section 16.1, to be used in the said Annual True-Up. The Annual True-Up shall also include the CWIP Supplement referred to in clause (ix).

(ii) The Annual True-Up will be filed with FERC by NSTAR in an informational filing on or before May 31 of the year following the Service Year and posted on NSTAR's website. The Annual True-Up so filed and posted shall include the actual report showing the basis for the computation of the Postretirement Benefits Other Than Pensions ("PBOP") component of "Administrative and General Expense" and shall also show the basis for the allocation of the PBOP expense to the service provided under this Local Service Schedule; provided that the information so filed and posted shall not include confidential information. The informational filing shall include a Benefits Labor Loader showing the basis for such allocation of both PBOP and prepaid pension costs. On request, NSTAR shall provide any Network Customer the Annual True-Up by May 31 of the year following the Service Year. Any difference between the estimated Embedded Cost Charge and the actual Embedded Cost Charge shall be collected from or refunded to the Network Customer in the month of June of the calendar year following the Service Year.

(iii) The Annual True-Up provided pursuant to Section 4.1(ii) shall include an attestation by a Company officer that "to the best of the affiant's knowledge, information and belief the data employed in the Annual True-Up reflect NSTAR's per book costs for the Service Year, conform to NSTAR's FERC Form 1 Report for the Service Year, conform in all material respects to the FERC Uniform System of Accounts, and have been developed in accordance with the provisions of this rate schedule."

(iv) The Annual True-Up shall also be accompanied by supplementary information which

shall (i) detail any data used in the Annual True-Up not directly taken from NSTAR's FERC Form 1 Report and (ii) identify any FERC Form 1 Account used to record expenses during the Service Year that was not used in the preceding Service Year. The supplementary information shall be certified by an officer of NSTAR.

(v) There shall be an "Audit Period" that will extend from July 1 through September 30 of the year following the Service Year; provided that NSTAR and the Network Customer may agree to extend the Audit Period beyond September 30 by their mutual written agreement. During the Audit Period, any Network Customer shall have the right to conduct an audit or other inspection of the actual data used in the Annual True-Up and/or request additional information not included with the Annual True-Up. NSTAR shall not withhold information, including PBOP information, on grounds of confidentiality, but is entitled to make such information available pursuant to a confidentiality agreement and to restrict access to non-competitive duty personnel and to other personnel whose receipt of the information would not be in violation of the Standards and/or Code of Conduct as prescribed by FERC. During the Audit Period, NSTAR shall exercise all commercially reasonable efforts to provide the Network Customer, within 10 business days, such additional information as the Network Customer may request in order to understand the Annual True-Up. To the extent requested, NSTAR shall meet with any Network Customer to provide such additional information, explanation, and/or clarification regarding the Annual True-Up as the Network Customer may request.

(vi) During the Audit Period, the Network Customer shall have the right to request NSTAR to adjust the Annual True-Up, and any refunds it received or payments it made, pursuant to the Annual True-Up to the extent of any discrepancy between the data employed by NSTAR in performing the Annual True-Up and the actual data for the Service Year or in the event NSTAR developed the Annual True-Up in a manner that is inconsistent with this rate schedule.

(vii) If NSTAR does not agree to the Network Customer's request, as set forth in subparagraph (vi), and if NSTAR and the Network Customer are in disagreement as to any component of the Annual True-Up, the Network Customer within thirty days following the conclusion of the Audit Period may request and NSTAR shall agree to non-binding dispute resolution either conducted with the FERC Staff or otherwise at the Network Customer's choice. The Network Customer may file a complaint with the Commission within thirty days following completion of the audit period or the dispute resolution process and shall specify in that

complaint the component or components of the Annual True Up that the Network Customer disputes. In the event such a complaint is filed, the disputed component or components of the Annual True Up shall be subject to refund as of the first day of the Service Year pending the results of the Commission investigation instituted as a result of such complaint. If the Network Customer fails to object to the Annual True-Up within thirty days following conclusion of the Audit Period, NSTAR's costs for the Service Year shall be deemed final, and its revenues from the Network Customer for the Service Year shall not be subject to refund; provided that the deadline for such an objection shall (i) be extended for ninety days following the date NSTAR makes any subsequent change to its Form 1 data for the Service Year that affects the Annual True-Up and (ii) shall not apply if the Commission prior to December 31st of the calendar year following the Service Year institutes its own investigation of NSTAR's Service Year costs.

(viii) Subject to the limitation that the Massachusetts Attorney General does not make or receive transmission payments or refunds, the Massachusetts Attorney General shall have the same procedural rights under this Section 4.0 as a Network Customer. This in no way obligates the Massachusetts Attorney General to the dispute resolution or arbitration procedures outlined in Sections 5.1 and 5.2.

(ix) The Annual True-Up shall include a CWIP Supplement, which shall apply to the Service Year, shall be filed with FERC by NSTAR in an informational filing on or before June 30 of the year following the Service Year and posted on NSTAR's website to the extent it does not include critical energy infrastructure information or other confidential information. The CWIP Supplement shall include NSTAR Electric's most recent annual construction forecast. The CWIP Supplement shall provide for each project included in rate base during the Service Year the actual amounts of CWIP recorded for each project, the related accounts, such as AFUDC and regulatory liability, inclusive of all subaccounts, and the resulting effect on the CWIP revenue requirement in line item detail. The CWIP Supplement shall also identify any changes in NSTAR's accounting practices related to the accrual of AFUDC and the inclusion of CWIP in rate base or related to ensuring that AFUDC is not accrued on CWIP balances that have been included in rate base.

For each "new project" (a project that is estimated to enter rate base for the first time in the Service Year), the CWIP Supplement shall provide, to the extent not included in the construction forecast, a detailed statement of the reasons for undertaking the project, the benefits to be derived

from the project, and the alternatives to or consequences of not undertaking the project. For each "pre-existing project" (a project that entered rate base prior to the Service Year), the CWIP Supplement shall include an update on the status of the project including any material change regarding the estimated cost of the project, the estimated in-service date and/or project timelines, and whether there is any change in the need for the project or in alternatives to the project. CWIP associated with a project cannot be included in the rate base for a Service Year unless it is included in the CWIP Supplement applicable to the Service Year.

The CWIP Supplement applicable to a Service Year shall include a CWIP Work Order/Project Reference Aid ("Reference Aid") that distinguishes between new projects and pre-existing projects and that provides for each project, whether new or pre-existing, ISO information, to the extent such information is available and applies to a project, and NSTAR information. The ISO information shall include a short description of the project, the year the project was approved through the ISO process, and the project identification number for ISO purposes. The NSTAR information shall include reference to the most recent NSTAR construction planning forecast in which the project appeared, the page of the plan at which the project description begins, the NSTAR numeric project designation, the NSTAR description of the project, the work order or work orders associated with the project, and a description of each work order. The Reference Aid shall present this information in a format so that the ISO information related to a project can be correlated with the NSTAR information related to a project. The Reference Aid, as described above, is based on current ISO and NSTAR tracking systems for projects under or proposed for construction and is to be modified to present equivalent information if and to the extent the ISO and/or NSTAR tracking system is modified.

The 50% of transmission-related CWIP included in rate base is subject to the Annual True-Up and dispute resolution provisions of this Section 4.1 regarding differences between actual and estimated costs. In addition, the CWIP included in rate base for a project shall be subject to refund as provided below to the extent the Commission makes a finding that the inclusion of such CWIP in rate base is unjust and unreasonable. In the case of a new project, the refund amount shall be the CWIP actually recovered from customers from the date of collection to the date of refund. In any proceeding regarding a new project, NSTAR shall bear the burden of proving that inclusion of CWIP related to the new project in rate base is just and reasonable. In the case of a pre-existing project, the refund amount shall be for the CWIP actually recovered from customers from the prospective refund effective date specified by the Commission pursuant to the

provisions of Section 206 of the Federal Power Act to the date of refund. All refunds shall include interest at the rate specified in 18 C.F.R. § 35.19a(a)(2)(iii). Any customer and/or the Massachusetts Attorney General can request that the Commission institute an investigation into the justness and reasonableness of including CWIP for any project in rate base and the Commission may institute such an investigation sua sponte.

Nothing in this Clause (ix) authorizes the inclusion in rate base of more than 50% of the CWIP balance attributable to a project. Absent a Commission finding of imprudence, NSTAR shall be entitled to accrue AFUDC as to any CWIP that is excluded from rate base. The Commission's institution of an investigation as to the justness and reasonableness of including CWIP associated with a project in rate base does not affect the timing or the finality of other components of the Annual True-Up as established by clause (vii) hereof.

With the exception of curtailment penalty charges pursuant to Section 16.2 and Schedule 3, paragraph 5 and Schedule 4, paragraph 6, any Annual True-Up rendered under this Local Service Schedule and any other monthly bill to which the Annual True-Up relates shall be binding on both Parties one (1) year from the date of NSTAR's Annual True-Up, unless previously disputed pursuant to this section or Section 4.3 of this Local Service Schedule.

4.2 Interest on Unpaid Balances

Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by NSTAR.

4.3 Customer Default

In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to NSTAR on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after NSTAR notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, NSTAR may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request.

In the event of a billing dispute between NSTAR and the Transmission Customer, NSTAR will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then NSTAR may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

5.0 DISPUTE RESOLUTION PROCEDURES

5.1 Internal Dispute Resolution Procedures

Any dispute between a Transmission Customer and NSTAR involving transmission service under this Local Service Schedule (excluding applications for rate changes or other changes to this Local Service Schedule, or to any Service Agreement entered into under this Local Service Schedule, which shall be presented directly to the Commission for resolution) shall be referred to a designated senior representative of NSTAR and a senior representative of the Transmission Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days [or such other period as the Parties may agree upon] by mutual agreement, such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below.

5.2 External Arbitration Procedures

Any arbitration initiated under this Local Service Schedule shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) days of the referral of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association and any applicable Commission regulations or ISO rules.

5.3 Arbitration Decisions

Unless otherwise agreed, the arbitrator(s) shall render a decision within ninety (90) days of appointment and shall notify the Parties in writing of such decision and the reasons therefore. The arbitrator(s) shall be authorized only to interpret and apply the provisions of this Local Service Schedule and any Service Agreement entered into under this Local Service Schedule and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act and/or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with the Commission if it affects jurisdictional rates, terms and conditions of service or facilities.

5.4 Costs

Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable:

(a) the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or

(b) one half the cost of the single arbitrator jointly chosen by the Parties.

5.5 Rights Under The Federal Power Act

Nothing in this section shall restrict the rights of any party to file a complaint with the Commission under relevant provisions of the Federal Power Act.

II LOCAL POINT-TO-POINT SERVICE

6.0 NATURE OF FIRM LOCAL POINT-TO-POINT SERVICE

6.1 Curtailment of Firm Local Point-To-Point Service

In the event a Transmission Customer (including Third-Party Sales by NSTAR) fails to curtail a transaction when requested to do so by NSTAR, the Local Control Center and/or ISO, as

appropriate and pursuant to this Section, NSTAR shall assess a penalty charge to the Transmission Customer. Said penalty charge will be determined in accordance with this Local Service Schedule.

In the event NSTAR, the Local Control Center or ISO exercises their rights to effect a Curtailment, in whole or in part, of Firm Local Point-To-Point Service, no credit or other adjustment shall be provided as a result of the Curtailment with respect to the charge payable by the Transmission Customer.

6.2 Classification of Firm Local Point-To-Point Service

(a) The Transmission Customer taking Firm Local Point-To-Point Service may, (1) change its Points of Receipt and Delivery to obtain service on a non-firm basis consistent with the terms of Part I, Section 10(a) of Schedule 21 of the OATT or (2) request a modification of the Points of Receipt or Delivery on a firm basis pursuant to the terms of Part I, Section 10(b) of Schedule 21 of the OATT; provided that NSTAR continues to be compensated for any costs associated with the construction or upgrading of facilities associated with the original firm service.

(b) In the event that a Transmission Customer’s use of the Transmission System (including Third-Party Sales by NSTAR) exceeds that Transmission Customer’s Reserved Capacity at any Point of Receipt or Point of Delivery in any hour, NSTAR will charge the Transmission Customer a penalty charge in accordance with Section 10 and Schedule 3 of this Local Service Schedule.

(c) Under no circumstance will NSTAR be obligated to provide Control Area Ancillary Services to the Transmission Customer in support of any excess capacity (i.e., capacity in excess of Transmission Customer’s Reserved Capacity).

7.0 NATURE OF NON-FIRM LOCAL POINT-TO-POINT SERVICE

7.1 Classification of Non-Firm Local Point-To-Point Service

In the event that a Transmission Customer’s use of the Transmission System (including Third-Party Sales by NSTAR) exceeds that Transmission Customer’s non-firm Reserved Capacity at any Point of Receipt or Point of Delivery, NSTAR will charge the Transmission

Customer a penalty charge in accordance with Section 10 and Schedule 4 of this Local Service Schedule for such excess. Under no circumstance will NSTAR be obligated to provide Control Area Ancillary Services to the Transmission Customer in support of any excess capacity (i.e., capacity in excess of Transmission Customer's Reserved Capacity).

7.2 Curtailment or Interruption of Service

In the event a Transmission Customer (including Third-Party Sales by NSTAR) fails to implement a Curtailment or Interruption when requested to do so by NSTAR, the Local Control Center and/or ISO, as appropriate and pursuant to this Section, NSTAR shall assess a penalty charge. Said penalty charge will be determined in accordance with Section 10 and Schedule 4 of this Local Service Schedule.

In the event NSTAR, the Local Control Center and/or ISO exercises its rights to effect a Curtailment, in whole or part, of Non-Firm Local Point-To-Point Service, no credit or other adjustment shall be provided as a result of the Curtailment with respect to the charge payable by the Transmission Customer.

In the event NSTAR, the Local Control Center and/or ISO exercises its rights to effect an Interruption, in whole or part, of Non-Firm Local Point-To-Point Service, the charge payable by the Transmission Customer shall be computed as if the term of service actually rendered were the term of service reserved; provided that an adjustment of the charge shall be made only when the Interruption is initiated by NSTAR, the Local Control Center and/or ISO, not when the customer fails to deliver energy to NSTAR.

8.0 SERVICE AVAILABILITY

8.1 Real Power Losses

Real power losses associated with transactions on NSTAR's Local Network shall be determined based on estimated average system losses for metering points on NSTAR's Local Network; the loss factor will be three and one tenth percent (3.1%).

8.2 Load Shedding

To the extent that a system contingency exists on the NSTAR Transmission System or the New England Transmission System and NSTAR, the Local Control Center or ISO, as appropriate,

determines that it is necessary to shed load, the Parties shall shed load in accordance with the procedures specified by NSTAR, the Local Control Center and/or ISO.

9.0 METERING

Unless otherwise agreed, the Transmission Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted under the Local Service Schedule and to communicate the information to NSTAR. However, NSTAR reserves the right to determine and approve any and all metering equipment and the metering installation design, such approval not to be unreasonably withheld.

All meters, including any recording devices or telemetry equipment must be operated and maintained in accordance with ISO Operating Procedures. Unless otherwise agreed, such equipment shall remain the property of NSTAR.

If at any time any metering equipment owned by NSTAR (or the Transmission Customer, if so agreed) is found to be inaccurate in excess of two percent (2%), up or down, the owner of the metering equipment shall cause it to be made accurate or replaced and the meter readings and rate computation for the period of inaccuracy shall be adjusted to correct such inaccuracy so far as the same can be reasonably ascertained, but no adjustment prior to the beginning of the next preceding month shall be made except by agreement of the Parties. In addition to an annual routine test, the owner of the metering equipment shall cause such equipment to be tested at any time upon written request of the other Party. If such equipment proves accurate within two percent (2%), up or down, the expense of the test shall be borne by the Party requesting the test. The determination of percent accuracy shall be in accordance with the weighted average percent registration as described in ANSI C12.1-1988, Section 6.1.8.1. The owner of the metering equipment shall comply with any reasonable request of the other Party concerning the sealing of meters, the presence of a representative when the seals are broken and tests are made, and other matters affecting the accuracy of the measurement of electricity hereunder.

10.0 COMPENSATION FOR LOCAL POINT-TO-POINT SERVICE

Rates for Firm and Non-Firm Local Point-To-Point Service shall be determined as set forth in the Schedules appended to this Local Service Schedule: Firm Local Point-To-Point Service (Schedule 3) and Non-Firm Local Point-To-Point Service (Schedule 4). Such rates shall be determined on the basis of estimated costs for each Service Year until the actual costs for such Service Year are determined.

Thereafter, payments made on such estimated costs shall be recalculated based on actual data for that Service Year, and an appropriate billing adjustment shall be made pursuant to Section 4 of this Local Service Schedule.

NSTAR shall use this Local Service Schedule to make its Third-Party Sales to be transmitted as Local Point-To-Point Service. NSTAR shall account for such use at the applicable rates, pursuant to Section II.8.5 of the Tariff.

11.0 STRANDED COST RECOVERY

NSTAR may seek to recover stranded costs from the Transmission Customer pursuant to this Local Service Schedule in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, NSTAR must separately file any specific proposed stranded cost charge under Section 205 of the Federal Power Act.

III LOCAL NETWORK SERVICE

12.0 NATURE OF LOCAL NETWORK SERVICE

12.1 Real Power Losses

Real power losses associated with transactions on Non-PTF shall be determined based on estimated average system losses for metering points on NSTAR's Local Network; the loss factor will be three and one tenth percent (3.1%).

12.2 Metering

Unless agreed otherwise, all meters, including any recording devices or telemetry equipment shall be owned, operated, maintained and tested by NSTAR or its Designated Agent in accordance with ISO Operating Procedures at the Transmission Customer's expense. NSTAR shall provide access to metering data, including telephone line access, which may reasonably be required to facilitate measurement and billing under a Service Agreement at the requesting Party's expense.

NSTAR reserves the sole right to determine appropriate metering installations. When new metering equipment is required, it shall be supplied by NSTAR, at the Transmission Customer's expense, including applicable taxes, and overhead costs, in conformity with ISO Operating

Procedures.

If at any time any metering equipment owned by NSTAR (or Transmission Customer, if so agreed) is found to be inaccurate in excess of two percent (2%), up or down, the owner of the metering equipment shall cause it to be made accurate or replaced and the meter readings and rate computation for the period of inaccuracy shall be adjusted to correct such inaccuracy so far as the same can be reasonably ascertained, but no adjustment prior to the beginning of the next preceding month shall be made except by agreement of the Parties. In addition to an annual routine test, the owner of the metering equipment shall cause such equipment to be tested at any time upon written request of the other Party.

If such equipment proves accurate within two percent (2%), up or down, the expense of the test shall be borne by the Party requesting the test. The determination of percent accuracy shall be in accordance with the weighted average percent registration as described in ANSI C12.1-1988, Section 6.1.8.1. The owner of the metering equipment shall comply with any reasonable request of the other Party concerning the sealing of meters, the presence of a representative when the seals are broken and tests are made, and other matters affecting the accuracy of the measurement of electricity hereunder.

13.0 NETWORK RESOURCES

13.1 Operation of Network Resources

The Network Customer shall not operate its designated Network Resources located in the Network Customer's or NSTAR's Control Area such that the output of those facilities exceeds its designated Local Network Load, plus Non-Firm Sales delivered pursuant to Part II of this Local Service Schedule, plus losses. This limitation shall not apply to changes in the operation of a Transmission Customer's Network Resources at the request of NSTAR to respond to an emergency or other unforeseen condition which may impair or degrade the reliability of the Transmission System.

13.2 Transmission Arrangements for Network Resources Not Physically Interconnected With NSTAR

The Network Customer shall be responsible for any arrangements necessary to deliver capacity and energy from a Network Resource not physically interconnected with NSTAR's Transmission

System. NSTAR will undertake reasonable efforts to assist the Network Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice.

13.3 Use of Interface Capacity by the Network Customer

Unless otherwise provided under the Tariff, there is no limitation upon a Network Customer's use of NSTAR's Transmission System at any particular interface to integrate the Network Customer's Network Resources (or substitute economy purchases) with its Local Network Loads. However, unless otherwise provided by the Tariff, a Network Customer's use of NSTAR's total interface capacity with other transmission systems may not exceed the Network Customer's Load.

13.4 Network Customer Owned Transmission Facilities

The Network Customer that owns existing transmission facilities that are integrated with NSTAR's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration the Network Customer must demonstrate that its transmission facilities are integrated into the plans or operations of NSTAR to serve its power and transmission customers. For facilities constructed by the Network Customer subsequent to the Service Commencement Date under this Local Service Schedule, the Network Customer shall receive credit where such facilities are jointly planned and installed in coordination with NSTAR. Calculation of the credit shall be addressed in either the Network Customer's Service Agreement or any other agreement between the Parties.

14.0 DESIGNATION OF LOCAL NETWORK LOAD

14.1 Local Network Load

The Network Customer must designate the individual Local Network Loads on whose behalf NSTAR will provide Local Network Service. The Local Network Loads shall be specified in the Service Agreement.

14.2 Local Network Load Not Physically Interconnected with NSTAR

This section applies to both initial designation pursuant to Section 15.1 and the subsequent addition of new Local Network Load not physically interconnected with NSTAR. To the extent that the Network Customer desires to obtain transmission service for a load outside NSTAR's Transmission System, the Network Customer shall have the option of (1) electing to include the

entire load as Local Network Load for all purposes under this Local Service Schedule and designating Network Resources in connection with such additional Local Network Load, or (2) excluding that entire load from its Local Network Load and purchasing Local Point-To-Point Service under this Local Service Schedule.

To the extent that the Network Customer gives notice of its intent to add a new Local Network Load as part of its Local Network Load pursuant to this section, the request must be made through a modification of service pursuant to a new Application.

15.0 LOAD SHEDDING AND CURTAILMENTS

15.1 Procedures

Prior to the Service Commencement Date, NSTAR and the Network Customer shall establish Load Shedding and Curtailment procedures pursuant to the OATT with the objective of responding to contingencies on the Transmission System. The Parties will implement such programs during any period when NSTAR, the Local Control Center or ISO, as appropriate, determines that a system contingency exists and such procedures are necessary to alleviate such contingency. NSTAR will notify all affected Network Customers in a timely manner of any scheduled Curtailment.

15.2 Allocation of Curtailments

NSTAR shall, on a non-discriminatory basis, effect a Curtailment of the transaction(s) that effectively relieves the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by NSTAR and Network Customer in proportion to their respective Load Ratio Shares. NSTAR shall not direct the Network Customer to effect a Curtailment of schedules to an extent greater than NSTAR would effect a Curtailment of NSTAR’s schedules under similar circumstances.

15.3 Load Shedding

To the extent that a system contingency exists on NSTAR’s Transmission System and ISO, the Local Control Center or NSTAR, as appropriate, determines that it is necessary for NSTAR, Local Point-to-Point Customers and Network Customers to shed load, the Parties shall shed load in accordance with the OATT.

15.4 System Reliability

Any Curtailment of Local Network Service will be not unduly discriminatory relative to NSTAR's use of the Transmission System on behalf of its Native Load Customers. In the event that the Network Customer fails to respond to established Load Shedding and Curtailment procedures, NSTAR shall assess a penalty charge. Said penalty charge will be determined in accordance with Section 16.2.

16.0 RATES AND CHARGES

Rates for Local Network Service shall be determined as set forth in this Section 16 on the basis of estimated costs for each Service Year until the actual costs for such Service Year are determined. Thereafter, payments made on such estimated costs shall be recalculated based on actual data for that Service Year, and all appropriate billing adjustments shall be made pursuant to Section 4 of this Local Service Schedule.

The Network Customer shall pay NSTAR for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following:

16.1 Monthly Demand Charge

The Network Customer shall pay a Monthly Demand Charge which shall be the Embedded Cost Charge. The Embedded Cost Charge shall be determined by multiplying the Network Customer's Load Ratio Share by one twelfth (1/12) of NSTAR's Annual Transmission Revenue Requirements, as determined in accordance with Attachment D of this Local Service Schedule and as subject to an Annual True-up pursuant to Section 4. The Embedded Cost Charge is based on NSTAR's system average embedded cost. In the event NSTAR seeks to apply a rate based on a methodology other than average embedded cost to all or any part of a Network Customer's service, either already being provided or proposed to be provided, NSTAR shall provide the affected Network Customer thirty days advance written notice of any filing with the Commission seeking to implement such a rate and shall comply with all applicable requirements of the Commission and the Tariff. Any dispute as to NSTAR's position concerning proposed cost allocation shall be addressed as provided in Section II.7(g) of Schedule 21-Local Service to Section II of the Tariff; provided that nothing in this provision prevents NSTAR from filing with the Commission at any time to establish new rates pursuant to the provisions of Section 205 of the FPA or a Network Customer from opposing such a filing, and nothing in this provision is intended to reflect a Network Customer's agreement that NSTAR has the rights set out in this

Section 16.1 or is intended to prevent the affected Network Customer from filing a complaint with the Commission at any time pursuant to the provisions of Section 206 of the FPA or NSTAR from opposing such a filing.

16.2 Curtailment Penalty Charge

If the Transmission Customer fails to respond to established emergency load shedding and curtailment procedures to relieve emergencies on the transmission system, NSTAR may assess a penalty charge to the Transmission Customer. Said penalty charge will be equal to two (2) times the Monthly Demand Charge for Local Network Service, as calculated in accordance with Section 16.1 of this Local Service Schedule, for the month in which such service was not curtailed or interrupted.

16.3 [Reserved]

16.4 Taxes and Fees Charge

16.4.1 If NSTAR incurs tax liability currently for which it will in subsequent years receive tax benefits (for example, a taxable contribution in aid of construction) then Transmission Customer shall pay to NSTAR an amount sufficient to reimburse NSTAR, on a net present value basis, for the reasonably projected costs resulting from the tax liability incurred in the current year less the reasonably projected tax benefits received by NSTAR in future years. Sections 16.4.1 and 16.4.2 are intended to apply to those Transmission Customers for whom Direct Assignment Facilities are constructed pursuant to this Local Service Schedule and to any Transmission Customer's appropriate share of the cost of any required Local Network Upgrades to the extent that any such Local Network Upgrade is identified pursuant to the study procedures outlined in Schedule 21-Local Service, Section II.7(d) and permitted or required by Commission ruling to be paid as a contribution in aid of construction.

16.4.2 If NSTAR takes a position that any particular transaction under any section of the Local Service Schedule does not constitute a transaction of the type described immediately above, and that position is subsequently reversed by Treasury ruling or regulation or court action, then the Transmission Customer shall pay to NSTAR an amount calculated as described above, but additionally taking into account any interest assessment required

to be paid by NSTAR.

16.4.3 At its effective date, this Section 16.4 applies only to contributions in aid of construction ("CIAC"). NSTAR reserves the right to file under Section 205 of the FPA to modify this provision to apply to items other than CIAC and the Network Customer reserves the right to oppose any such filing.

17.0 OPERATING ARRANGEMENTS

17.1 Operating Requirements

The terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of this Local Service Schedule shall be specified in the OATT. The OATT shall provide for the Parties to:

(i) operate and maintain equipment necessary for integrating the Network Customer within NSTAR's Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment),

(ii) transfer data between NSTAR and the Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside NSTAR's Transmission System, interchange schedules, unit outputs for redispatch required under Section 15, voltage schedules, loss factors and other real time data),

(iii) use software programs required for data links and constraint dispatching,

(iv) exchange data on forecasted loads and resources necessary for long-term planning, and

(v) address any other technical and operational considerations required for implementation of this Local Service Schedule, including scheduling protocols.

The OATT will recognize that the Network Customer shall either:

(i) operate as a Control Area under applicable guidelines of the Electric Reliability Organization (ERO), as defined in 18 CFR 38.1, and ISO,

(ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with NSTAR, or

(iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies the applicable reliability guidelines of the ERO and ISO. NSTAR shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services.

17.2 Network Operating Committee

A Network Operating Committee (Committee) shall be established to coordinate operating criteria for the Parties' respective responsibilities under the OATT. Each Network Customer shall be entitled to have at least one representative on the Committee. The Committee shall meet from time to time as need requires, but no less than once each calendar year.

SCHEDULE 2

SUPPLEMENTAL END-USE REACTIVE SUPPORT SERVICE

In the event that power factor levels and reactive supply requirements set forth in the service agreement or other associated operating or interconnect agreement are not maintained by the Delivering Party (or, as appropriate, the Receiving Party), in accordance with applicable ISO standards and practices then NSTAR shall charge the Transmission Customer to take corrective action. The Transmission customer shall compensate NSTAR for installing the necessary equipment, whether in the form of generating units or other non-generating resources, such as demand resources, to correct the incremental difference between the Transmission Customer's lowest (or highest) power factor level and that which is an acceptable level in accordance with ISO standards and practices. The charges will be based upon the necessary level of reactive power supply required to correct the deficiency in the power factor level.

For the KVAR demand supplied to the Transmission Customer, the charge shall be the greater of a) the market price of installing leading reactive power supply expressed in terms of $/KVAR or b) $50/KVAR of installed (leading) reactive power reflecting current NSTAR cost.

For the KVAR demand absorbed by NSTAR the charge shall be the greater of a) the market price of installing lagging reactive power supply expressed in terms of $/KVAR or b) $22.5/KVAR of installed (lagging) reactive power reflecting current NSTAR cost.

SCHEDULE 3

LONG-TERM FIRM AND SHORT-TERM FIRM

LOCAL POINT-TO-POINT SERVICE

The Transmission Customer shall compensate NSTAR for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following charges as applicable:

1) Annual Rate

The Annual Rate for Firm Local Point-To-Point Service shall consist of the higher of (i) the Embedded Cost Charge or (ii) the Incremental Cost Charge, as set forth below:

(i) The Embedded Cost Charge shall be determined by dividing NSTAR's Annual Transmission Revenue Requirements (determined in accordance with Attachment D of this Local Service Schedule) by the maximum amount of NSTAR's Monthly Transmission System Load during such Service Year.

(ii) The Incremental Cost Charge shall be determined from the total costs of all Local Network Upgrades plus other incremental costs incurred provided for in the Service Agreement application to a transaction. If the Incremental Cost Charge is higher, the Transmission Customer shall pay for the facilities necessary to provide it with service during an amortization period, with the Transmission Customer paying the Embedded Cost Charge upon completion of the amortization. Such amortization period shall be coterminous with the Service Agreement.

2) Firm Local Point-To-Point Service for Monthly Transactions or Longer Term Transactions

The charge for each month applicable to a monthly transaction or longer term transaction (the "Monthly Rate") shall be determined as the product of: (a) NSTAR's Annual Rate for Firm Local Point-To-Point Service divided by twelve (12) months and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Service Agreement for such month, expressed in kilowatts.

3) Firm Local Point-To-Point Service for Less Than One Month

NSTAR's Weekly Rate is equal to NSTAR's Annual Rate for Firm Local Point-To-Point Service divided by fifty-two (52) weeks. NSTAR's Daily Rate is equal to NSTAR's Annual Rate for Firm Local Point-To-Point Service divided by three hundred and sixty-five (365) days. NSTAR's Hourly Rate is equal to

NSTAR's Annual Rate for Firm Local Point-To-Point Service divided by eight thousand seven hundred and sixty (8,760) hours.

The Transmission Customer shall pay the Weekly, Daily or Hourly Rate, as applicable, times the Reserved Capacity set forth in the Transmission Customer's Applicable Service Agreement.

4) <u>Penalty</u>

When the Transmission Customer exceeds its Reserved Capacity or uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved (Excess Incident), NSTAR will charge the Transmission Customer 200% of the rate determined as follows for each kilowatt of the Excess Incident:

- The unreserved use penalty for a single hour of unreserved use shall be based on the rate for daily Firm Point-to Point Transmission Service.

- If there is more than one assessment for a given duration (e.g., daily) for the Transmission Customer, the penalty shall be based on the next longest duration (e.g., weekly).

- The unreserved penalty charge for multiple instances of unreserved use (i.e., more than one hour) within a day shall be based on the daily rate for Firm Point-To-Point Transmission Service.

- The unreserved penalty charge for multiple instances of unreserved use isolated to one calendar week shall be based on the charge for weekly Firm Point-To-Point Transmission Service.

- The unreserved use penalty charge for multiple instances of unreserved use during more than one week during a calendar month shall be based on the charge for monthly Firm Point-To-Point Transmission Service.

- The unreserved use penalty charge for multiple instances of unreserved use during more than one month during a calendar year shall be based on the charge for yearly Firm Point-To-Point Transmission Service.

All Excess Incidents will be recorded by NSTAR, and if in any calendar year more than ten (10) Excess Incidents occur in connection with service for the Transmission Customer, then NSTAR may require the Transmission Customer to apply for additional Firm Local Point-To-Point Service under this Local

Service Schedule in the amount equal to the highest Excess Incident during that Service Year. Charges for such additional transmission service will relate back to the first day of the month following the month of NSTAR's notice.

5) Curtailment Penalty Charge

If the Transmission Customer fails to respond to established emergency load shedding and curtailment procedures to relieve emergencies on the Transmission System, NSTAR may assess a penalty charge to the Transmission Customer. Said penalty charge will be equal to two (2) times the Monthly Rate for Firm Local Point-To-Point Service for the month in which such service was not curtailed or interrupted.

6) Taxes and Fees Charge

A) If any governmental authority requires the payment of any fee or assessment not specifically provided for in any of the charge or rate provisions under this Local Service Schedule or imposes a sales, gross revenue, or other form of tax with respect to payments made for service provided under this Local Service Schedule, including any applicable interest charged on any deficiency assessment made by the taxing authority, together with any further tax on such payments, the obligation to make payment for any such fee, assessment, or tax shall be borne by the Transmission Customer. NSTAR will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's Regulations.

B) If NSTAR incurs tax liability currently for which it will, in subsequent years, receive tax benefits (for example, a taxable contribution in aid of construction), the Transmission Customer shall pay to NSTAR an amount sufficient to reimburse NSTAR, on a net present value basis, for the reasonably projected costs resulting from the tax liability incurred in the current year less the reasonably projected tax benefits received by NSTAR in future years.

C) If NSTAR takes a position that any particular transaction under any section of this Local Service Schedule does not constitute a transaction of the type described immediately above, and that position is subsequently reversed by Treasury ruling or regulation, or court action, then the Transmission Customer shall pay to NSTAR an amount calculated as described above but additionally taking into account any interest assessment required to be paid by NSTAR.

7) Regulatory Expense Charge

NSTAR shall have the right to make a Section 205 filing for recovery of regulatory expenses associated with this Local Service Schedule and the Service Agreement(s).

8) Customer-Related Expense Charge

NSTAR shall charge the Transmission Customer, in addition to the other charges assessed pursuant to this Local Service Schedule, and as set forth in its Service Agreement for those costs attributable to the billing, meter reading, record keeping, (all from FERC Uniform System of Accounts Nos. 901-905) and an allocation of administrative and general expenses (FERC Uniform System of Accounts Nos. 920-935) associated with each of these costs, all of which are related to the Transmission Customer's Local Point-To-Point Service and allocated on the basis of the total number of customers served by NSTAR.

9) Exchanges

With respect to any transactions that involve an exchange, each party to such transaction shall be an individual Transmission Customer under this Local Service Schedule. Accordingly, a transmission charge, as applicable, will be calculated for, and a separate bill will be rendered to, each such Transmission Customer.

10) Discounts

Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by NSTAR must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, NSTAR must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

11) Resales

The rates and rules governing charges and discounts shall not apply to resales of transmission service, compensation for which shall be governed by § I.11(a) of Schedule 21.

SCHEDULE 4

<u>NON-FIRM LOCAL POINT-TO-POINT SERVICE</u>

The Transmission Customer shall compensate NSTAR for any Ancillary Services and for Non-Firm Local Point-To-Point Service up to the sum of the applicable charges set forth below:

1) The Annual Rate for Non-Firm Local Point-To-Point Service shall be NSTAR's Annual Transmission Revenue Requirements (determined in accordance with Attachment D of this Local Service Schedule) for the Service Year divided by NSTAR's Monthly Transmission System Load during such Service Year.

2) <u>Non-Firm Local Point-To-Point Service for Monthly Transactions or Longer Term Transactions</u>
The charge for each month applicable to a monthly transaction or longer term transaction (the "Monthly Rate") shall be determined as the product of: (a) NSTAR's Annual Rate for Non-Firm Local Point-To-Point Service divided by twelve (12) months and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Service Agreement for such month, expressed in kilowatts.

3) <u>Non-Firm Local Point-To-Point Service for Less Than One Month</u>
NSTAR's Weekly Rate is equal to NSTAR's Annual Rate for Non-Firm Local Point-To-Point Service divided by fifty-two (52) weeks.

NSTAR's Daily Rate is equal to NSTAR's Annual Rate for Non-Firm Local Point-To-Point Service divided by three hundred and sixty-five (365) days. NSTAR's Hourly Rate is equal to NSTAR's Annual Rate for Non-Firm Local Point-To-Point Service divided by eight thousand seven hundred and sixty (8,760) hours.

The Transmission Customer shall pay the Weekly, Daily or Hourly Rate, as applicable, time the Reserved Capacity set forth in the Transmission Customer's Applicable Service Agreement.

4) <u>Credit to the Transmission Charge</u>
Whenever service provided hereunder is interrupted or curtailed by NSTAR, or its Designated Agent including ISO, the Transmission Charges to the Transmission Customer calculated pursuant to Sections 2 and 3 of this Schedule 4 shall be credited by an amount equal to the sum of the credits calculated for each hour of interruption or curtailment in service. The credit to the Transmission Customer for each hour of

interruption or curtailment shall be calculated as the product of (a) NSTAR's Hourly Rate and (b) the kilowatts of service interruption or curtailment during such hour.

5) <u>Penalty</u>

When the Transmission Customer exceeds its Reserved Capacity or uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved (Excess Incident), NSTAR will charge the Transmission Customer 200% of the rate determined as follows for each kilowatt of the Excess Incident:

- The unreserved use penalty for a single hour of unreserved use shall be based on the rate for daily Firm Point-to Point Transmission Service.

- If there is more than one assessment for a given duration (e.g., daily) for the Transmission Customer, the penalty shall be based on the next longest duration (e.g., weekly).

- The unreserved penalty charge for multiple instances of unreserved use (i.e., more than one hour) within a day shall be based on the daily rate for Firm Point-To-Point Transmission Service.

- The unreserved penalty charge for multiple instances of unreserved use isolated to one calendar week shall be based on the charge for weekly Firm Point-To-Point Transmission Service.

- The unreserved use penalty charge for multiple instances of unreserved use during more than one week during a calendar month shall be based on the charge for monthly Firm Point-To-Point Transmission Service.

- The unreserved use penalty charge for multiple instances of unreserved use during more than one month during a calendar year shall be based on the charge for yearly Firm Point-To-Point Transmission Service.

All Excess Incidents will be recorded by NSTAR, and if in any calendar year more than ten (10) Excess Incidents occur in connection with service for the Transmission Customer, then NSTAR may require the Transmission Customer to apply for additional Non-Firm Local Point-To-Point Service under this Local Service Schedule in the amount equal to the highest Excess Incident during that Service Year. Charges for such additional Non-Firm Local Point-To-Point Service will relate back to the first day of the month following the month of NSTAR's notice.

6) Curtailment Penalty Charge.

If the Transmission Customer fails to respond to established emergency load shedding and curtailment procedures to relieve emergencies on the Transmission System, NSTAR may assess a penalty charge to the Transmission Customer. Said penalty charge will be equal to two (2) times the monthly demand charge for Non-Firm Local Point-To-Point Service for the month in which such service was not curtailed or interrupted.

7) Taxes and Fees Charge

A) If any governmental authority requires the payment of any fee or assessment not specifically provided for in any of the charge or rate provisions under this Local Service Schedule or imposes a sales, gross revenue, or other form of tax with respect to payments made for service provided under this Local Service Schedule, including any applicable interest charged on any deficiency assessment made by the taxing authority, together with any further tax on such payments, the obligation to make payment for any such fee, assessment, or tax shall be borne by the Transmission Customer. NSTAR will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's Regulations.

B) If NSTAR incurs tax liability currently for which it will, in subsequent years, receive tax benefits (for example, a taxable contribution in aid of construction), the Transmission Customer shall pay to NSTAR an amount sufficient to reimburse NSTAR, on a net present value basis, for the reasonably projected costs resulting from the tax liability incurred in the current year less the reasonably projected tax benefits received by NSTAR in future years.

C) If NSTAR takes a position that any particular transaction under any section of this Local Service Schedule does not constitute a transaction of the type described immediately above, and that position is subsequently reversed by Treasury ruling or regulation, or court action, then the Transmission Customer shall pay to NSTAR an amount calculated as described above but additionally taking into account any interest assessment required to be paid by NSTAR.

8) Regulatory Expense Charge

NSTAR shall have the right to make a Section 205 filing for recovery of regulatory expenses associated with this Local Service Schedule and the Service Agreement(s).

9) Customer-Related Transaction Charge

NSTAR shall charge the Transmission Customer, in addition to the other charges assessed pursuant to this Local Service Schedule, and as set forth in its Service Agreement for those costs attributable to the billing, meter reading, record keeping, (from FERC Uniform System of Accounts Nos. 901-905) and an allocation of administrative and general expenses (Nos. 920-935) associated with each of these costs, all of which are related to the Transmission Customer's Local Point-To-Point Service and allocated on the basis of the total number of customers served by NSTAR.

10) Exchanges

With respect to any transactions that involve an exchange, each party to such transaction shall be an individual Transmission Customer under this Local Service Schedule. Accordingly, a transmission charge, as applicable, will be calculated for, and a separate bill will be rendered to, each such Transmission Customer.

11) Discounts

Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by NSTAR must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, NSTAR must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

12) Resales

The rates and rules governing charges and discounts shall not apply to resales of transmission service, compensation for which shall be governed by § I.11(a) of Schedule 21.

ATTACHMENT A

METHODOLOGY TO ASSESS AVAILABLE TRANSFER CAPABILITY

1. Introduction

ISO is the regional transmission organization (“RTO”), serving the New England Control Area. ISO is responsible for development, oversight, and fair administration of New England’s wholesale market and management of bulk electric power system and wholesale markets' planning processes. The ISO serves as the Balancing Authority for the New England Control Area. The New England Control Area is interconnected to three neighboring Balancing Authority Areas: New Brunswick System Operator Area (“NBSO Area”), New York Independent System Operator Area (“NYISO Area”), and Hydro-Québec TransÉnergie Area (“HQTÉ Area”).

As part of its RTO responsibilities, the ISO is registered with the North American Electric Reliability Corporation (“NERC”) as several functional model entities that have responsibilities related to the calculation of ATC as defined in the following NERC Standards: MOD-001 – Available Transmission System Capability (“MOD-001”), MOD-004 – Capacity Benefit Margin (“MOD-004”), and MOD-008 – Transmission Reliability Margin Calculation Methodology (“MOD-008”). The extent of those responsibilities is based on various Commission-approved transmission operating agreements and the provisions of the ISO New England Operating Documents.

While the ISO is the transmission provider for transmission service associated with PTF, the Participating Transmission Owners (PTOs) under the Transmission Operating Agreement, such as NSTAR, provide local transmission service over Non-Pool Transmission Facilities within the RTO footprint and are responsible for calculating TTC and ATC associated with Local Service provided under Schedule 21. Pursuant to CFR § 37.6(b)[1] of the Commission’s regulations, NSTAR as a Transmission Provider is obligated to calculate and post ATC and TTC for certain local facilities over which Point-to-Point transmission service is provided under Schedule 21-NSTAR. These are primarily radial paths that provide transmission service to directly interconnected generators.

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[1] §37.6(b) Posting transfer capability. The available transfer capability (ATC) on the Transmission Provider’s system and the total transfer capability (TTC) of that system shall be calculated and posted for each Posted Path as set forth in this section.

Posted Path is defined as any control area-to-control area interconnection; any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a

customer requests to have ATC or TTC posted. For this last category, the posting must continue for 180 days and thereafter until 180 days have elapsed from the most recent request for service over the requested path. For purposes of this definition, an hour includes any part of any hour during which serviced was denied, curtailed or interrupted. §37.6(b)(1)(i).

NSTAR does not currently have any Posted Paths based on the above definition. However, to the extent that NSTAR does in the future have any Posted Path(s), NSTAR will calculate ATC and TTC using NERC Standard MOD-029-1 Rated System Path Methodology as outlined below.

1.1 Scope of Document

The scope of this document is limited to the following functions which are performed or utilized by NSTAR in order to provide Local Point-to Point Service under Schedule 21-NSTAR: Total Transfer Capability (TTC) methodology; Available Transfer Capability (ATC) methodology; Existing Transmission Commitment (ETC); Use of Transmission Reliability Margin (TRM); Use of Capacity Benefit Margin (CBM); and Use of Rollover Rights (ROR) in the calculation of ETC.

TTC and ATC are required to be calculated only for certain non-PTF internal paths over which Local Point-to-Point Service is provided under Schedule 21-NSTAR. TTC and ATC are not calculated by NSTAR for Local Network Service because ISO employs a market model for economic, security constrained dispatch of generation, and NSTAR does not require advance reservation for such network service.

2. Transmission Service in the New England Markets

Since the inception of the open access transmission tariff for New England, the process by which generation located inside New England supplies energy and/or capacity to the bulk electric system has differed from the Commission's pro forma open access transmission tariff. The fundamental difference is that internal generation is dispatched in an economic, security constrained manner by the ISO rather than utilizing a system of physical rights, advance reservations and point-to-point transmission service. Through this process, internal generation provides offers that are utilized by the ISO in the Real-Time Energy Market dispatch software. This process provides the least-cost dispatch to satisfy Real-Time load on the system.

In addition to offers from generation within New England, entities may submit energy transactions that move into the New England Control Area, out of the New England Control Area or through the New

England Control Area. The Real-Time Energy Market clears these External Transactions based on forecast LMPs and the transfer capability of the associated external interfaces. With those External Transactions in place, the Real-Time Energy Market dispatches internal generation in an economic, security constrained manner to meet Real-Time load within the region.

The process for submitting External Transactions into the Real-Time Energy Market does not require an advance physical reservation for use of the PTF. In the event that the net of economic External Transactions is greater than the transfer capability of the associated external interface, the ExternalTransactions selected to flow are selected based on the rules specified in the Tariff. For any External Transactions that are confirmed to flow in Real-Time based on the economics of the system, a transmission reservation for RNS and Through-or-Out Service is created after-the-fact to satisfy the transparency needs of the market.

The process described above is applicable to the PTF within the New England Control Area, and non-PTF where utilized for Local Network Service by generation or load. However, NSTAR owns local transmission facilities over which an advance transmission service reservation for firm or non-firm transmission service may be required. On those facilities, Market Participants may obtain a transmission service reservation from NSTAR under Schedule 21-NSTAR prior to delivery of energy and/or capacity into the New England markets pursuant to Schedule 18, 20A or 20B of the Tariff. This document addresses the calculation of ATC and TTC for these non-PTF internal paths.

3. NSTAR Total Transfer Capability (TTC)

TTC is the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions. TTC for Schedule 21-NSTAR is calculated using NERC Standard MOD-029-1 Rated System Path Methodology and posted on the NSTAR OASIS site.

The TTC on NSTAR's Non-PTF that requires Local Point-to-Point Service reservations are relatively static values. NSTAR calculates the TTC for Posted Paths as the rating of the particular radial transmission path.NSTAR will calculate and post TTC on its OASIS site for all non-PTF Posted Paths that are eligible for Local Point-to-Point Service reservations. TTC is calculated as the transfer capability rating of the particular radial transmission path less the most limiting element within the PostedPath.

4. Capacity Benefit Margin (CBM)

CBM is defined as the amount of firm transmission transfer capability set aside by a Transmission Provider for use by the Load Serving Entities. The ISO does not set aside any CBM for use by the Load Serving Entities, because of the New England approach to capacity planning requirements in the ISO New England Operating Documents, and in any event, ISO's determination of CBM does not apply directly to the determination of ATC for Local Service. Load Serving Entities operating with the New England Control Area are required to arrange for their Capacity Requirements prior to the beginning of any given month in accordance with the Tariff, Section III.13.7.3.1 (Calculation of Capacity Requirement and Capacity Load Obligation). Load Serving Entities do not utilize CBM to ensure that their capacity needs are met; therefore, CBM is not applicable within the New England market design. Accordingly, for purposes of NSTAR's ATC calculation and because CBM for the New England Control Area is set to zero (0), NSTAR utilizes a zero (0) CBM value.

5. Transmission Reliability Margin (TRM)

TRM is the amount of transmission transfer capability set aside to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. It is used only for external interfaces under the New England market design. As NSTAR does not have any external interfaces, TRM for its non-PTF facilities is presently set to zero.

6. Existing Transmission Commitments

6.1 Existing Transmission Commitments, Firm (ETC_F)

ETC_F are confirmed Firm Local Point-To-Point Transmission Service reservations (PTP_F) plus any exercised rollover rights for Firm Point-To-Point Transmission Service reservations (ROR_F). There are no allowances necessary for Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$), grandfathered Transmission Service (GF_F), and other services, contracts or agreements (OS_F) to be considered in the ETC_Fcalculation.

6.2 Existing Transmission Commitments, Non-Firm (ETC_{NF})

ETC_{NF} are confirmed Non-Firm transmission reservations (PTP_{NF}). There are no allowances necessary for Non-Firm Network Integration Transmission Service ($NITS_{NF}$), Non-Firm grandfathered Transmission Service (GF_{NF}), or other services, contracts or agreements (OS_{NF}).

7. Calculation of ATC for NSTAR's Transmission System

NERC Standards MOD-001-1 – Available Transmission System Capability and MOD-029-1 – Rated

System Path Methodology define the required items to be identified when describing a Transmission Provider's ATC methodology. As a practical matter, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

Common practice is not to calculate or post firm and non-firm ATC values for the Non-PTF assets, as ATC is positive and listed as 9999. Transmission Customers are not restricted from reserving Firm or Non-Firm Point-to-Point Service on Non-PTF facilities.

As Real-Time approaches, the ISO utilizes the Real-Time Energy Market rules to determine which of the submitted energy transactions will be scheduled in the coming hour. Basically, the ATC of the non-PTF assets in the New England market is almost always positive. The ATC is equal to the amount of net energy and/or capacity transactions that the ISO will schedule on an interface for the designated hour. With this simplified version of ATC, there is no detailed algorithm to be described or posted other than: ATC equals TTC. Thus, for those non-PTF that serve as a path for NSTAR's Transmission Customers taking Local Point-to-Point Service, NSTAR has posted the ATC as 9999, consistent with industry practice. ATC on these paths varies depending on the time of day. However, it is posted with an ATC of "9999" to reflect the fact that there are no restrictions on these paths for commercial transactions.

7.1 Calculation of Schedule 21-NSTAR Firm ATC (ATC_F)

7.1.1 Calculation of ATC_F in the Planning Horizon (PH)

For purposes of this Attachment A, PH is any period before the Operating Horizon.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for TRM, CBM, ETC_F, $Postbacks_F$ and $counterflows_F$. As discussed above, TRM and CBM are zero. Firm Transmission Service under Schedule 21-NSTAR that is available in the PH includes: Yearly, Monthly, Weekly and Daily. $Postbacks_F$ and $counterflows_F$ of Schedule 21-NSTAR transmission reservations are not considered in the ATC calculation. Therefore, ATC_F in the PH is equal to the TTC minus ETC_F.

7.1.2 Calculation of ATC_F in the Operating Horizon (OH)

For purposes of this Attachment A, OH begins noon eastern prevailing time each day. At that time, the OH spans from noon through midnight of the next day for a total of 36 hours. As time progresses, the total hours remaining in the OH decrease until noon the following day when the OH is once again reset to

36 hours.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for ETC_F, CBM, TRM, $Postbacks_F$ and $counterflows_F$. As discussed above, TRM and CBM are zero. Daily Firm Transmission Service under Schedule 21-NSTAR is the only firm service offered in the OH. $Postbacks_F$ and $counterflows_F$ of Schedule 21-NSTAR transmission reservations are not considered in the ATC_F calculation. Therefore, ATC_F in the OH is equal to the TTC minus ETC_F.

7.1.3 Calculation of ATC_F in the Scheduling Horizon (SH)

Because Firm Schedule 21-NSTAR transmission service is not offered in the SH, ATC_F in the SH is zero.

7.2 Calculation of Schedule 21-NSTAR Non-Firm ATC (ATC_{NF})

7.2.1 Calculation of ATC_{NF} in the PH

ATC_{NF} is the capability for Non-Firm transmission reservations that remain after allowing for ETC_F, ETC_{NF}, scheduled CBM (CBM_S), unreleased TRM (TRM_U), Non-Firm Postbacks ($Postbacks_{NF}$) and Non-Firm counterflows ($counterflows_{NF}$). As discussed above, the TRM and CBM for Schedule 21-NSTAR are zero. ATC_{NF} available in the PH includes: Monthly, Weekly, Daily and Hourly. TRM_U, $Postbacks_{NF}$ and $counterflows_{NF}$ of Schedule 21-NSTAR transmission reservations are not considered in this calculation. Therefore, ATC_{NF} in the PH is equal to the TTC minus ETC_F and ETC_{NF}.

7.2.2 Calculation of ATC_{NF} in the OH

ATC_{NF} available in the OH includes: Daily and Hourly. As discussed above, the TRM and CBM for Schedule 21-NSTAR are zero. TRM_U, $counterflows_{NF}$ and ETC_{NF} of Schedule 21-NSTAR transmission reservations are not considered in this calculation. Therefore, ATC_{NF} in the OH is equal to the TTC minus ETC_F plus postbacks of PTP_F in the OH as PTP_{NF} ($Postbacks_{NF}$).

7.3 Negative ATC

As stated above, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available. As also stated above, NSTAR's Non-PTF are primarily radial paths that provide transmission service to directly interconnected generators. It is possible that in the future a particular radial path may interconnect more nameplate capacity generation than the path's TTC. For the local facilities modeled by ISO, and consistent with ISO's economic, security-constrained dispatch methodology, the ISO will only dispatch an amount of generation

interconnected to such path so as not to incur a reliability or stability violation on the subject path. Therefore, ATC in the PH, OH and SH could become zero, but will never be negative.

8. Posting of Schedule 21-NSTAR ATC

8.1 Location of ATC Posting

ATC values are posted on the NSTAR OASIS site.

8.2 Updates to ATC

When any of the variables in the ATC equations change, the ATC values are recalculated and immediately posted.

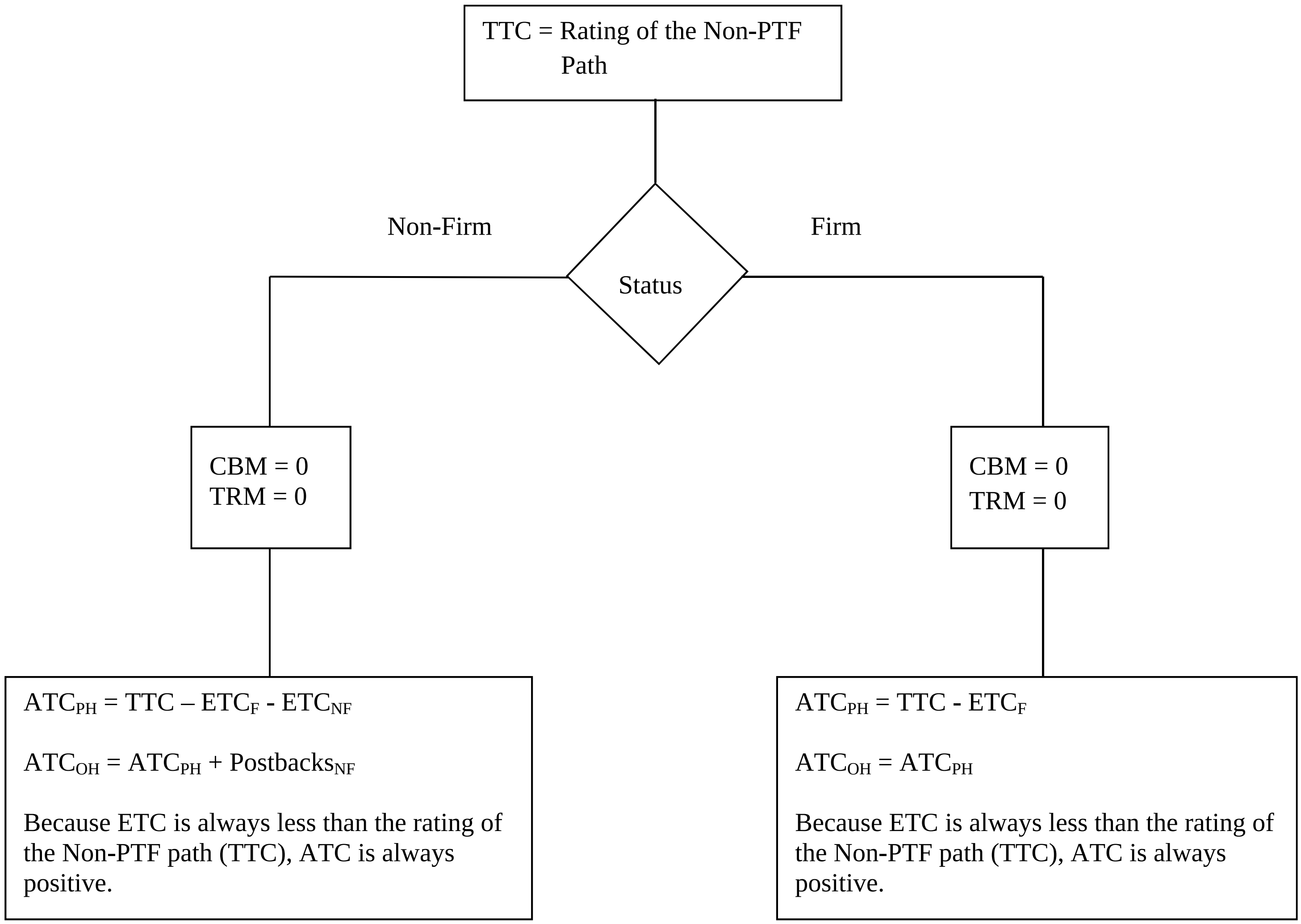
8.3 Coordination of ATC Calculations

NSTAR's Non-PTF has no external interfaces. Therefore, it is not necessary to coordinate the values.

8.4 Mathematical Algorithms

The mathematical algorithms for the calculation of ATC can be found on NSTAR's web site at http://www.nstar.com/business/rates_tariffs/open_access/docs/ATC_Algorithm-Sch_21.pdf

Non-PTF Transmission Path ATC Process Flow Diagram



ATTACHMENT B

<u>METHODOLOGY FOR COMPLETING A SYSTEM IMPACT STUDY</u>

When NSTAR determines on a non-discriminatory basis that a System Impact Study is needed because its Transmission System will be inadequate to accommodate a Completed Application for service, the following outlines the study methodology that NSTAR will employ to estimate the Transmission System impact of a Completed Application for Firm Local Point-To-Point Service, Network Integration Service and/or any costs associated with Direct Assignment Facilities and/or Local Network Upgrades that would be incurred in order to accommodate the service requested in the Completed Application.

1. <u>System Impact will be estimated based on consideration of reliability requirements to</u>:

- meet obligations under agreements that predate this Local Service Schedule;
- meet obligations of existing and pending Completed Application under this Local Service Schedule;
- maintain thermal, voltage and stability system performance within acceptable regional practices.

2. <u>Guidelines and Principles followed by NSTAR</u>: When performing the System Impact Study, NSTAR will apply the following, as amended and/or adopted from time to time.

- Good Utility Practice;
- Criteria, rules and reliability standards applicable to the New England Transmission System;
- NPCC criteria and guidelines; and
- NSTAR criteria and guidelines.

3. <u>Transmission System Model Representation</u>: The Transmission System model will be based on a library of load flow cases prepared by ISO for studies of the New England area. The models may include representations of other NPCC and neighboring systems. These load flow cases include individual system model representations provided by Transmission Owners and represent forecasted system conditions for up to ten (10) years into the future. This library of load flow cases is maintained and updated as appropriate by ISO, and is consistent with information filed under FERC Form 715. NSTAR will use system models that it deems appropriate for study of the Completed Application for service. Additional system models and operating conditions, including assumptions specific to a particular analysis, may be developed for conditions not available in the library of load flow cases. The system models may be modified, if necessary, to include additional system information on load, transfers and

configuration, as it becomes available.

4. System Conditions: Loading of all Transmission System elements shall be less than normal ratings for pre-contingency conditions and less than long-term emergency (LTE) ratings for post-contingency conditions. Post-contingency loading above LTE rating and less than short-term emergency (STE) rating may be allowed where demonstrated that loading can be reduced below the LTE rating within fifteen (15) minutes. Transmission System voltage shall be within the applicable design ratings of connected equipment for normal and emergency conditions. Normal and post-contingency voltages shall be in accordance with NSTAR and ISO standards.

5. Short Circuits: Transmission System short circuit currents shall be within the applicable equipment design ratings.

6. Study Analysis: System impact of the integration of new load will be evaluated to meet the requirements of design, identified in the guidelines and principles under Item 2 above, to provide sufficient transmission capability to maintain stability and to maintain thermal and voltage levels of lines and equipment within applicable limits. The same applies to the evaluation of Firm Point-To-Point Service when it has been determined that insufficient transfer capability is available and the Eligible Customer requests a System Impact Study be conducted.

7. Loss Evaluation: The impact of losses on the Transmission System will be taken into account in the System Impact Study to ensure Good Utility Practice in the design and operation of its system.

8. System Protection: Protection requirements will be evaluated by NSTAR in accordance with ISO, NPCC, and NSTAR criteria.

9. Approvals: NSTAR will conduct the System Impact Study to ensure compliance with its planning and design policies and practices. However, the actions to be taken by the Parties to implement the recommendations of the System Impact Study are subject to approval under the Tariff.

10. Study Scope and Reporting: The study will determine the impacts and identify changes required, if any, to NSTAR’s existing Transmission System. NSTAR will provide the Eligible Customer with a written report of the physical interconnection alternative(s), required NSTAR system additions and/or modifications, if any, associated study grade cost estimates (+/- 25%) and the results of the analysis.

ATTACHMENT C

INDEX OF LOCAL POINT-TO-POINT SERVICE CUSTOMERS

Customer	Date of Service Agreement
AIG Trading Corporation	October 29, 1996
Altresco Pittsfield Light Plant	December 26, 1996
Aquila Power Company	February 26, 1997
Axia Energy, LP	June 20, 2001
Baltimore Gas & Electric Co.	January 14, 1997
Bangor Hydro-Electric Co.	October 1, 1996
Belmont Municipal Light Dept.	December 11, 1996
Central Vermont Public Service	January 3, 1997
Chicopee Municipal Light Dept.	October 2, 1996
CINERGY Capital and Trading, Inc.	January 1, 1998
CINERGY Operating Companies	December 1, 1997
Citizens Lehman Power Sales	November 6, 1996
Constellation Power Source, Inc.	July 11, 1997
Duke Energy Solutions, Inc.	March 19, 1999
DukeSolutions, Inc.	May 18, 1999
Edison Source	June 9, 1997
Electric Clearinghouse, Inc.	October 7, 1996
Entergy Nuclear Generation Company	April 10, 2003
Equitable Power Services Company	October 29, 1996
Green Mountain Power Corporation	January 10, 1997
HQ Energy Services (US) Inc.	February 8, 1999
LG&E Power Marketing, Inc.	October 8, 1996
Maine Public Service Company	September 30, 1996
Massachusetts Bay Transportation Authority	May 1, 1999
Massachusetts Municipal Wholesale Electric Co.	September 6, 1996
Merchant Energy Group of the Americas, Inc.	August 16, 1998
Mirant Canal, LLC	July 6, 1998
Mirant Americas Energy Marketing, LP	April 28, 2004
Montaup Electric Co.	October 15, 1996

Morgan Stanley Capital Group, Inc.	October 29, 1996
NEPOOL on Behalf of NEPOOL Participants	June 1, 1997
New England Power Company	December 30, 1996
New York State Gas & Electric Corp.	December 16, 1997
NorAm Energy Services	November 14, 1997
Northeast Energy Services, Inc.	June 17, 1997
NP Energy, Inc.	August 1, 1997
NRG Power Marketing, Inc.	January 1, 2001
NSTAR Electric Company	December 24, 1996
PECO Energy Power Team	January 3, 1997
Rainbow Energy Power Marketing	November 7, 1996
Reading Municipal Light Department	September 6, 1996
Sithe New England Holdings, LLC	January 3, 1998
Sonat Power Marketing, Inc.	November 14, 1997
Southern Energy Trading and Marketing, Inc.	March 10, 1997
Strategic Energy Ltd.	May 11, 1999
The Power Company of America	November 18, 1996
Town of Braintree Electric Light Dept.	September 6, 1996
Town of Hingham Municipal Light Plant	September 9, 1996
Town of Hull Municipal Light Plant	December 11, 1996
Trans Alta Energy Marketing	November 24, 1998
Trans Canada Power Corporation	January 27, 1997
Western Power Services, Inc.	December 24, 1996
Williams Energy Services Company	July 17, 1997
VTEC Energy, Inc.	March 24, 1998

ATTACHMENT D

<u>ANNUAL TRANSMISSION REVENUE REQUIREMENTS</u>

The Transmission Revenue Requirements for NSTAR ("the Company") will reflect the costs for its Transmission System, including costs attributable to those incurred by the Company in owning, leasing, maintaining and supporting the Transmission System net of revenues for transmission services provided under any other FERC accepted tariff or under any contract with other parties that provides reimbursement to the Company for transmission related services. Under no circumstances shall the Company's Local Network Service rates include costs that are charged through any other rate or tariff. The Transmission Revenue Requirements will be an annual calculation based on the estimated costs for its Transmission System during the Service Year.

The Company shall make an annual informational filing with the FERC on or before May 31 of each year which shall include a True-up of estimated costs and revenues, and actual costs and revenues for the preceding Service Year. Actual costs will be determined using data required to be reported annually in the FERC Form 1 and recorded on the Company's books in accordance with FERC's Uniform System of Accounts; unless the use of other data, such as subaccount balances, is specifically required by the provisions below, in which case an officer of the Company, shall certify that the development, accuracy and application of such other data is in accordance with the provisions of this Local Service Schedule. Such certification will be included with the annual informational filing along with adequate detail that supports the values contained within the True-up calculation. References to specific FERC Form 1 pages, line numbers and columns included in this Local Service Schedule are based on the 2006 Form 1 of the Company's predecessor entities. Subsequent FERC changes to Form 1 may be adopted to the extent they are consistent with the provisions and terms of this Local Service Schedule and not otherwise prohibited by FERC.

I. <u>DEFINITIONS</u>

Capitalized terms not otherwise defined in Section II.1 of the OATT or the Local Service Schedule and as used herein have the following definitions:

A. <u>ALLOCATION FACTORS</u>

1. <u>Transmission Wages and Salaries Allocation Factor</u> shall equal the ratio of transmission-related direct wages and salaries including those of affiliated companies as reported in the

Company’s annual FERC Form 1, page 354, line 21, column (b) to the Company’s total direct wages and salaries including those of the affiliated companies as reported in the Company’s FERC Form 1, page 354, line 28, column (b), and excluding administrative and general wages and salaries as reported in the Company’s FERC Form 1, page 354, line 27, column (b).

2. Plant Allocation Factor shall equal the ratio of the sum of Transmission Plant, excluding HQ leases, plus Transmission Related Intangible and General Plant to Total Plant in Service excluding HQ Leases.

B. TERMS

Administrative and General Expense shall equal the expenses as reported in the Company’s FERC Form 1, page 323, line 197, column (b), excluding Property Insurance included in FERC Account No. 924, Regulatory Commission Expense included in FERC Account No. 928, and Advertising Expense included in FERC Account No. 930.1 and excluding Merger-Related Costs included in FERC Account Nos. 920-935 (other than those in FERC Account Nos. 924, 928 and 930.1, which have already been excluded). The amount of Postretirement Benefits Other Than Pensions (“PBOP”) expense in FERC Account No. 926 shall be separately stated as a footnote to the Company’s FERC Form 1, page 323, line 187, column (b): Current Year and column (c): Previous Year.

Amortization of Gain on Reacquired Debt shall equal the amortization amount recorded in FERC Account No. 429.1.

Amortization of Loss on Reacquired Debt shall equal the expenses as recorded in FERC Account No. 428.1.

Amortization of Investment Tax Credits shall equal the credits as recorded in FERC Account No. 411.4.

Depreciation Expense for Transmission Plant shall equal the transmission expenses as recorded in FERC Account No. 403 as reported in the Company’s annual FERC Form 1 page 336, line 7, column (f).

General Plant shall equal the gross plant balance as recorded in FERC Account Nos. 389-399.

General Plant Depreciation and Amortization Expense shall equal the general plant expenses as recorded in FERC Account Nos. 403 for depreciable items and 404 for items subject to amortization as reported in the Company's annual FERC Form 1, page 336, line 10, column (f).

General Plant Depreciation Reserve shall equal the general reserve balance as recorded in FERC Account No. 108 and reported in the Company's annual FERC Form 1, page 219, line 28, column (b).

General Plant Amortization Reserve shall equal the general reserve balance as recorded in FERC Account No. 111 and reported in the Company's annual FERC Form 1, page 200 in a footnote to line 14.

Hydro-Quebec DC Facilities (HQ Leases) shall equal the balance in capital leases as recorded in FERC Account Nos. 350-359 and FERC Account Nos. 389-399.

Intangible Plant shall equal the gross plant balance as recorded in FERC Account No. 303 as reported in the Company's annual FERC Form 1, page 205, line 4, column (g). The only allowable Intangible Plant for inclusion in the Local Service Schedule are software, patent or rights costs.

Intangible Plant Amortization Expense shall equal amortization expenses as recorded in FERC Account Nos. 404-405 as reported in the Company's annual FERC Form 1, page 336, line 1, column (f). The only allowable Intangible Plant Amortization Expense for inclusion in the Local Service Schedule is the amortization of software, patent or rights costs.

Intangible Plant Amortization Reserve shall equal the amortization reserve balance as recorded in FERC Account No. 111. The only allowable Intangible Plant Amortization Reserve for inclusion in the Local Service Schedule is that related to the amortization of software, patent or rights costs.

Merger-Related Costs shall equal NSTAR Electric's amortized merger-related costs as authorized by FERC or by state regulatory order.

Other Regulatory Assets/Liabilities - FAS 106 shall equal the net of the FAS 106 balance as recorded in FERC Account No. 182.3 and any FAS 106 balance as recorded in the FERC Account No. 254.

Other Regulatory Assets/Liabilities - FAS 109 shall equal the net of the FAS 109 asset and any FAS 109 balance liability.

Payroll Taxes shall equal those payroll expenses as recorded in the FERC Account No. 408.1.

Plant Held for Future Use shall equal the balance in FERC Account No. 105 that relates to land and land rights which have been purchased for future transmission use, or transmission related projects that were included in this account before January 1, 2007.

Prepayments shall equal the prepayment balance as recorded in FERC Account No. 165, plus any prepayment specifically related to the Company's Pension plans related to electric company operations recorded in FERC Account No. 182.3, Other Regulatory Assets.

Property Insurance shall equal the expenses as recorded in FERC Account No. 924.

Total Accumulated Deferred Income Taxes shall equal the net of the deferred tax balance as recorded in FERC Account Nos. 281-283 and 190 for those balances that are directly related to transmission, excluding those directly related to distribution or other businesses.

Total Gain on Reacquired Debt shall equal the gain as recorded in FERC Account No. 257.

Total Loss on Reacquired Debt shall equal the expenses as recorded in FERC Account No. 189.

Total Municipal Tax Expense shall equal the municipal tax expenses as recorded in FERC Account No. 408.1 as reported in the Company's annual FERC Form 1, page 263, line 10, column (i).

Total Plant in Service shall equal the total gross plant balance as recorded in FERC Account Nos. 301-399 excluding HQ Leases recorded in those accounts.

Total Transmission Depreciation Reserve shall equal the transmission reserve balance as recorded in FERC Account No. 108 as reported in the Company's annual FERC Form 1, page 219, line 25, column (b), excluding HQ-related amounts recorded in that account.

Transmission Depreciation Expense shall be the annual depreciation expense for transmission accounts computed using the following rates, as approved by FERC in Docket No. ER03-1274:

Account	Description	Rate

Account	Description	Rate
352	Structures and Improvements	2.19%
353	Station Equipment	2.53%
354	Towers and Fixtures	2.03%
355	Poles and Fixtures	2.25%
356	Overhead Conductors and Devices	2.19%
357	Underground Conduit	2.06%
358	Underground Conductors and Devices	2.15%
359	Roads and Trails	1.63%

Transmission Merger-Related Costs shall equal NSTAR Electric's amortized merger-related transmission costs as authorized by FERC.

Transmission Operation and Maintenance Expense shall equal all transmission-related expenses as recorded in FERC Account Nos. 560-564 and 566-576.5, and shall exclude; (i) all HQ HVDC expenses recorded in those accounts, and (ii) expenses billed to the Company by ISO-NE for Scheduling and Dispatch Service.

Transmission Plant shall equal the balance as recorded in FERC Account Nos. 350-359.1, adjusted to exclude the capital leases in the Hydro-Quebec DC Facilities (HQ Leases).

Transmission Plant Materials and Supplies shall equal the balance as assigned to transmission, as recorded in FERC Account No. 154 as reported in the Company's annual FERC Form 1, page 227, lines 5 and 8, column (c).

II. CALCULATION OF TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirement shall equal the sum of (A) Return and Associated Income Taxes, (B) Transmission Depreciation and Amortization Expense, (C) Transmission Related Amortization of Gain/Loss on Reacquired Debt, (D) Transmission Related Amortization of Investment Tax Credits, (E) Transmission Related Municipal Tax Expense, (F) Transmission Related Payroll Tax Expense, (G) Transmission Operation and Maintenance Expense, (H) Transmission Related Administrative and General Expenses, (I) Transmission Related Integrated Facilities Charges, minus (J) Transmission Support Revenue, plus (K) Transmission Support Expense, plus (L) Transmission-Related Expense from

Generators, minus (M) Transmission Rents Received from Electric Property, minus (N) Short-Term and Non-Firm Point-To-Point Service Revenues, minus (O) Regional Network Services (RNS) Revenues, minus (P) Through or Out Revenues, minus (Q) ISO-NE Scheduling and Dispatch Revenues.

A. Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate.

1. Transmission Investment Base

The Transmission Investment Base will be the year end balances of (a) Transmission Plant, plus (b) Transmission Related Intangible and General Plant, plus (c) Transmission Plant Held for Future Use, plus (d) 50 percent of Transmission Related Construction Work In Progress (CWIP), less (e) Transmission Related Depreciation and Amortization Reserve, less (f) Transmission Related Accumulated Deferred Taxes, less, (g) AFUDC Regulatory Liability, plus (h) Transmission Related Gain/Loss on Reacquired Debt, plus (i) Other Regulatory Assets/Liabilities, plus (j) Transmission Prepayments, plus (k) Transmission Materials and Supplies, plus (l) Transmission Related Cash Working Capital.

(a) Transmission Plant will equal the balance of the investment in Transmission Plant. This value excludes the capital leases in the Hydro-Quebec DC Facilities (HQ Leases).

(b) Transmission Related Intangible and General Plant shall equal the sum of the balance of investment in Intangible Plant and General Plant multiplied by the Transmission Wages and Salaries Allocation Factor.

(c) Transmission Plant Held for Future Use shall equal the land and land rights portion of the balance of Transmission-related Plant Held for Future Use (FERC Account No. 105) plus the non-land Plant Held for Future Use related to projects that were included in Account No. 105 prior to January 1, 2007 to the extent such non-land plant has not been closed to Plant In Service; such balances to be provided in conformance with the FERC Uniform System of Accounts, Instruction E, Account No. 105 which requires that "…property included in this account shall be classified according to detail accounts (301-399)…and shall be maintained in such detail as though the property were in service."

(d) 50 Percent of Transmission Related Construction Work in Process (CWIP) shall equal the balance of Transmission related investment in FERC Account 107 multiplied by 50%, subject to any exclusions pursuant to the provisions of Section 4.1 of this Local Service Schedule.

(e) Transmission Related Depreciation and Amortization Reserve shall equal the balance of Total Transmission Depreciation Reserve as reported in the Company's annual FERC Form 1, page 219 line 25, column (b), plus the balance of Transmission Related Intangible Plant Amortization Reserve, Transmission Related General Plant Depreciation Reserve and Transmission Related General Plant Amortization Reserve. Transmission Related Intangible Plant Amortization Reserve, Transmission Related General Plant Depreciation Reserve and Transmission Related General Plant Amortization Reserve shall equal the product of (i) the sum of the Intangible Plant Amortization Reserve, General Plant Depreciation Reserve and General Plant Amortization Reserve and (ii) the Transmission Wages and Salaries Allocation Factor. The Total Transmission Depreciation Reserve balance excludes any amounts related to the capital leases in the Hydro-Quebec DC Facilities (HQ Leases).

(f) Transmission Related Accumulated Deferred Taxes shall equal the electric balance of Total Accumulated Deferred Income Taxes (for those balances that are directly related to transmission, plus the balances not directly related to other businesses), with the remaining accumulated deferred taxes not directly related to other businesses being allocated on the same basis used for the related rate base assets.

(g) AFUDC Regulatory Liability shall equal 50% of the capitalized AFUDC booked on transmission projects as recorded in FERC Account No. 254.

(h) Transmission Related Gain/Loss on Reacquired Debt shall equal the electric balance of Total Gain/Loss on Reacquired Debt multiplied by the Plant Allocation Factor.

(i) Other Transmission Related Regulatory Assets/Liabilities shall equal the electric balance of any deferred rate recovery of FAS 106 expenses multiplied by the Transmission Wages and Salaries Allocation Factor, plus the electric balance of FAS 109 multiplied by the Plant Allocation Factor.

(j) Transmission Prepayments shall equal the electric balance of Prepayments multiplied by the Transmission Wages and Salaries Allocation Factor.

(k) Transmission Materials and Supplies shall equal the electric balance of Transmission Plant Materials and Supplies.

(l) Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of the Transmission Operation and Maintenance Expense included in Section II.G, Transmission Related Administrative and General Expenses included in Section II.H, and Transmission Support Expenses included in Section II.K.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) the Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital for Service Years ending before January 1, 2013 will be calculated based 70% upon the capital structure at the end of each year and 30% upon a pro-forma capital structure consisting of 50% debt, 0% preferred, and 50% common equity; thereafter the pro-forma capital structure will be the same as the actual capital structure, and will equal the sum of (i), (ii) and (iii) below. Notwithstanding the foregoing, for Service Years ending before January 1, 2013, NSTAR's Weighted Cost of Capital will be the lower of the blended rate as calculated herein or the actual rate.

(i) the long-term debt component, which equals the product of: the actual weighted average embedded cost to maturity of the long-term debt then outstanding; and the sum of (a) the ratio that long-term debt is to the total capital multiplied by 70%, plus (b) 50% pro-forma capital structure multiplied by 30%.

(ii) the preferred component shall be the product of: the embedded cost of preferred stock outstanding at the end of each year; and the sum of (a) the ratio that preferred stock is to the total capital multiplied by 70%, plus (b) 0% pro-forma capital structure multiplied by 30%.

(iii) the return on equity component shall be the product of: the allowed ROE of the common equity; and the sum of (a) the ratio that common equity is to the total capital multiplied by 70%, plus (b) 50% pro-forma capital structure multiplied by 30%. The allowed ROE shall be 10.57%, plus any additional incentive ROE adders as may be applied to specific investment approved by the Commission pursuant to Order No. 679, provided that the total ROE for any project, including any such ROE incentives, shall be capped by the top of the applicable zone of reasonableness determined by FERC for the relevant period. The allowed ROE shall be subject to revision at any time by unilateral filing by NSTAR under Section 205 of the FPA or by such Section 205 filing by NSTAR on a joint basis with other New England transmission owners. In either case, the revised ROE shall become effective no later than sixty days after the filing in accordance with the provisions of the FPA and also subject to any suspension or refund condition which the Commission may order pursuant to its authority under that Section. Any filing made by NSTAR to revise the ROE in compliance with a Commission order shall become effective as of the date specified in such order and shall raise no issue regarding this Local Service Schedule other than the compliance with the Commission order. The allowed ROE is also subject to revision pursuant to the authority of the Commission under Sections 205 and 206 of the FPA.

(b) Federal Income Tax shall equal

$$\frac{(A+[(C+B)/D])(FT)}{1 - FT}$$

where FT is the Federal Income Tax Rate and A is the weighted return on equity component, including preferred, as determined in Sections II.A.2.(a)(ii) and (iii) above, B is Transmission Related Amortization of Investment Tax Credits, as determined in Section II.D below, C is the equity AFUDC component of Transmission Depreciation and Amortization Expense, as defined in Section II.B below, and D is Transmission Investment Base, as determined in Section II.A.1 above.

(c) State Income Tax shall equal

$$\underline{(A+[(C+B)/D] + \text{Federal Income Tax})(ST)}$$

1 – ST

where ST is the State Income Tax Rate, A is the weighted return on equity component, including preferred, determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section II.D below, C is the equity AFUDC component of Transmission Depreciation and Amortization Expense, as defined in Section II.B below, D is the Transmission Investment Base, as determined in II.A.1 above and Federal Income Tax is the rate determined in Section II.A.2.(b) above.

B. Transmission Depreciation and Amortization Expense shall equal the sum of (i) the Depreciation Expense for Transmission Plant and (ii) an allocation of Intangible Plant Amortization Expense and General Plant Depreciation Expense, which is calculated by multiplying the sum of (a) Intangible Plant Amortization Expense and (b) General Plant Depreciation Expenses by the Transmission Wages and Salaries Allocation Factor; less the Amortization of AFUDC Regulatory Credit as recorded in FERC Account No. 407.4.

C. Transmission Related Amortization of Gain/Loss on Reacquired Debt shall equal the electric Amortization of Gain/Loss on Reacquired Debt multiplied by the Plant Allocation Factor.

D. Transmission Related Amortization of Investment Tax Credits shall equal the electric Amortization of Investment Tax Credits multiplied by the Plant Allocation Factor.

E. Transmission Related Municipal Tax Expense shall equal the total electric municipal tax expense reported in the Company's FERC Form 1, page 263, Local Real Estate and Personal Property Taxes, column (i), multiplied by the Plant Allocation Factor.

F. Transmission Related Payroll Tax Expense shall equal the total electric payroll tax expense reported in the Company's FERC Form 1, page 263, Service Company Allocations and Capitalization, column (i), multiplied by the Transmission Wages and Salaries Allocation Factor.

G. Transmission Operation and Maintenance Expense shall equal the Transmission Operation and Maintenance Expenses in Section I.B above.

H. Transmission Related Administrative and General Expenses shall equal the sum of the (1)

Administrative and General Expense multiplied by the Transmission Wages and Salaries Allocation Factor, (2) Property Insurance included in FERC Account No. 924, line 156 multiplied by the Transmission Plant Allocation Factor, (3) expenses included in Account No. 928 (excluding Merger-Related Costs included in Account No. 928), line 160 related to (i) transmission related FERC Assessments, plus (ii) any other Federal and State transmission related expenses or assessments, plus (iii) the cost of any independent audit requested by the Mass AG as the representative for NSTAR's retail customers and (4) Transmission Merger-Related Costs. The amount of PBOP expense shall be separately stated. NSTAR commits to adhere to: (i) the Commission's PBOP policy as expressed in the Commission's December 17, 1992, Statement of Policy in Docket No. PL93-1-000, as the Commission may amend that policy from time to time in the future; and (ii) the provisions of Financial Accounting Statement 106, Employers' Accounting for Postretirement Benefits Other Than Pensions.

I. Transmission Related Integrated Facilities Charges shall equal the transmission payments to Affiliates for use of the integrated transmission facilities of those Affiliates included in FERC Account No. 565.

J. Transmission Support Revenues shall equal the revenue received for transmission support included or includable in FERC Account Nos. 454 and 456 but excluding any revenue received for use of the Company's entitlement in the Hydro-Quebec Facilities.

K. Transmission Support Expense shall equal the expense paid by the Company for transmission support included in FERC Account No. 565, but excluding expenses for the Hydro-Quebec DC Facilities.

L. Transmission-Related Expense from Generators shall equal the expenses from generators that are reflected in a filing made by the Company with the Commission under Section 205 of the Federal Power Act and accepted by the Commission for recovery under the Local Service Schedule and included or includable in FERC Account No. 565.

M. Transmission Rents Received from Electric Property shall equal any FERC Account Nos. 454 and 456 Rents from Electric Property, associated with Transmission Plant but not reflected as a credit in Transmission Support Revenues in Section II.J.

N. Short-Term and Non-Firm Point-to-Point Service Revenues shall equal the applicable wheeling revenues received for Local Point-To-Point Service provided under this Local Service Schedule, including the transmission component of the Company's Third-Party Sales, as recorded in FERC Account Nos. 447 and 456.1.

O. Regional Network Services (RNS) Revenues shall equal the Company's RNS revenues pursuant to the Tariff, as included or includable in FERC Account Nos. 454, 456 and 456.1 but excluding any incremental revenues associated with FERC-approved adders for RTO participation and new investment.

P. Through or Out Revenues shall equal the distribution of revenues received by the Company for Through or Out Service pursuant to the Tariff as included or includable in FERC Account Nos. 454 and 456.1.

Q. ISO-NE Scheduling and Dispatch Revenues shall be the amount of revenues received by the Company from ISO-NE for scheduling and dispatch services pursuant to the Tariff as included or includable in FERC Account Nos. 454, 456 and 456.1.

ATTACHMENT E

INDEX OF LOCAL NETWORK SERVICE CUSTOMERS

Customer	Date of Service Agreement
ANP Blackstone Energy Company	October 1, 2000
Entergy Nuclear Generation Company	September 1, 1999
New England Power Company	September 6, 1996
NSTAR Electric Company	December 24, 1996
Sithe New Boston LLC	September 1, 1998
Sithe Framingham LLC	September 1, 1998
Sithe Mystic LLC	September 1, 1998
Sithe Edgar LLC	September 1, 1998
Sithe West Medway LLC	September 1, 1998
Town of Braintree Municipal Light Dept.	March 1, 1997
Town of Concord Municipal Light Plant	June 21, 2002
Town of Hingham Municipal Light Plant	March 1, 1997
Town of Hull Municipal Light Plant	March 1, 1997
Town of Norwood Municipal Light Dept.	September 6, 1996
Town of Reading Municipal Light Plant	March 1, 1997
Town of Wellesley Municipal Light Plant	June 21, 2002

ATTACHMENT F

<u>FORMULA RATE TEMPLATE</u>

NSTAR Electric Company

Annual Local Network Service Revenue Requirement

Service Year Ended December 31, xxxx

This template does not change the other provisions of this Schedule 21. The template is not a substitute for Schedule 21 language. If an inconsistency between the Schedule 21 language and the template arises, the Schedule 21 language is controlling. The template is illustrative and the actual true-up filing as made from time to time may include format changes or reflect non-material changes required by the Uniform System of Accounts.

Sheet 1

	(a)	(b)	(c)	(d)
Line	Description	Section	Amount	Reference
1	**Investment Base**	II.A.1		
2	Transmission Plant	II.A.1.a	$ -	Sheet 3, Line 1, Col (f)
3	Transmission Related Intangible & General Plant	II.A.1.b	-	Sheet 3, Line 4, Col (f)
4	Transmission Plant Held for Future Use	II.A.1.c	-	Sheet 3, Line 5, Col (f)
5	Transmission Related Construction Work in Progress	II.A.1.d	-	Sheet 3, Line 6, Col (f)
6	Total Plant		-	Sum Lines 2 thru 5
7	Trans Related Depreciation and Amortization Reserve	II.A.1.e	-	Sheet 3, Line 12, Col (f)
8	Transmission Related Accumulated Deferred Taxes	II.A.1.f	-	Sheet 3, Line 20, Col (f)
9	AFUDC Regulatory Liability	II.A.1.g	-	Sheet 3, Line 21, Col (f)
10	Total Net Plant		-	Sum Lines 6 thru 9
11	Transmission Related Gain/Loss on Reacquired Debt	II.A.1.h	-	Sheet 3, Line 22, Col (f)
12	Other Trans Related Regulatory Assets/Liabilities	II.A.1.i	-	Sheet 3, Line 28, Col (f)
13	Transmission Prepayments	II.A.1.j	-	Sheet 3, Line 29, Col (f)
14	Transmission Materials & Supplies	II.A.1.k	-	Sheet 3, Line 30, Col (f)
15	Transmission Related Cash Working Capital	II.A.1.l	-	Sheet 3, Line 35, Col (f)
16	**Total Investment Base**		$ -	Sum Lines 10 thru 15
17	**Revenue Requirement**			
18	Investment Return and Income Taxes	II.A.2	$ -	Sheet 2, Line 39, Col (c)
19	Transmission Depreciation and Amortization Expense	II.B	-	Sheet 4, Line 7, Col (f)
20	Amortization of Gain/Loss on Reacquired Debt	II.C	-	Sheet 4, Line 8, Col (f)
21	Transmission Related Amort. of Investment Tax Credits	II.D	-	Sheet 4, Line 9, Col (f)
22	Transmission Related Municipal Tax Expense	II.E	-	Sheet 4, Line 10, Col (f)
23	Transmission Related Payroll Tax Expense	II.F	-	Sheet 4, Line 11, Col (f)
24	Transmission Operation & Maintenance Expense	II.G	-	Sheet 4, Line 30, Col (f)
25	Trans Related Administrative and General Expense	II.H	-	Sheet 4, Line 44, Col (f)
26	Transmission Related Integrated Facilities Charges	II.I	-	Sheet 5, Line 10, Col (e)
27	Transmission Support Revenues	II.J	-	Sheet 5, Line 15, Col (e)
28	Transmission Support Expense	II.K	-	Sheet 5, Line 20, Col (e)
29	Transmission Related Expense from Generators	II.L	-	Sheet 5, Line 23, Col (e)
30	Transmission Rents Received from Electric Property	II.M	-	Sheet 5, Line 28, Col (e)
31	Short-Term and Non-Firm P-T-P Service Revenues	II.N	-	Sheet 5, Line 31, Col (e)
32	Regional Network Services (RNS) Revenues	II.O	-	Sheet 5, Line 36, Col (e)
33	Through or Out Revenues	II.P	-	Sheet 5, Line 39, Col (e)
34	ISO-NE Scheduling and Dispatch Revenues	II.Q	-	Sheet 5, Line 43, Col (e)
35	**Total LNS Revenue Requirement**		**$ -**	Sum Lines 18 thru 34
36	Wholesale LNS Revenues Received:			
37	Item # 1		-	
38	Item #2		-	

39	Last Item	-	
40	Total Wholesale LNS Revenue	$ -	Sum Lines 37 thru 39
41	**Total Retail LNS Revenue Requirement**	**$ -**	Line 35 - Line 40
42	Average 12 CP		
43	Sum of Monthly Peaks (kw)	-	FF1: 400.17(b)
44	Average Peak	-	Line 43 / 12
45	Annual Rate per kw	$ -	Line 35 / Line 44
46	Monthly Rate per kw	$ -	Line 45 / 12
47	Daily Rate per kw	$ -	Line 45 / 365

NSTAR Electric Company

Investment Return and Income Taxes

Service Year Ended December 31, xxxx

Sheet 2

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Line	**Description**	**Tariff Section**	**Balance**	**Capitalization Ratio ***	**Cost ***	**Weighted Cost ***	**Equity Cost**	**Reference**
1	**Weighted Cost of Capital**	II.A.2.a						
2	Long Term Debt	II.A.2.a.i	$ -		0.0000%	0.0000%		FF1: Page 112.24(c)
3	Preferred Stock	II.A.2.a.ii	-		0.0000%	0.0000%	0.0000%	FF1: Page 112.3(c)
4	Common Equity	II.A.2.a.iii	-		0.0000%	0.0000%	0.0000%	FF1: Page 112.16(c) - Line 3(c)
5	Total		$ -			0.0000%	0.0000%	Sum Lines 2 thru 4
6	**Investment Return**	II.A.2						
7	Total Investment Base		$ -					Sheet 1, Line 16, Col (c)
8	Weighted Cost of Capital		0.0000%					Line 5, Col (f)
9	Total Return on Investment		$ -					Line 7 * Line 8
10	**Federal Income Tax**	II.A.2.b						
11	A = Equity Cost		0.0000%					Line 5, Col (g)
12	B = Transmission Amortization of ITC		$ -					Sheet 1, Line 21, Col (c)
13	C = Equity AFUDC		-					FF1: Page 117.38
14	Total B + C		-					Line 12 + Line 13
15	D = Investment Base		-					Line 7
16	(B + C) / D		0.00%					Line 14 / Line 15
17	(A + [(C + B) / D]		0.00%					Line 11 + Line 16
18	FT = Federal Income Tax Rate		35.00%					Federal corporate tax rate
19	1 - FT		65.00%					1 - Line 18
20	Federal Tax Factor		0.00000%					Line 17 * Line 18 / Line 19
21	Total Federal Income Taxes		$ -					Line 15 * Line 20
22	**State Income Tax**	II.A.2.c						
23	A = Equity Cost		0.0000%					Line 5, Col (g)
24	B = Transmission Amortization of ITC		$ -					Sheet 1, Line 21, Col (c)
25	C = Equity AFUDC		-					
26	Total B + C		-					Line 24 + Line 25
27	D = Investment Base		-					Line 7
28	(B + C) / D		0.00%					Line 26 / Line 27
29	(A + [(C + B) / D]		0.00%					Line 23 + Line 28
30	ST = State Income Tax Rate		6.50%					Massachusetts corporate tax rate
31	1 - ST		93.50%					1 - Line 30
32	Federal Tax Factor		0.00000%					Line 23
33	State Tax Factor		0.00000%					(Line 29 + Line 32) * Line 30 / Line 31
34	Total State Income Taxes		$ -					Line 27 * Line 33
35	**Investment Return and Income Taxes**	II.A.2						
36	Return on Investment		$ -					Line 9

37	Federal Income Taxes	-	Line 21
38	State Income Taxes	-	Line 34
39	**Total Return and Income Taxes**	**$ -**	Sum Lines 36 thru 38

* Note that weighting and cost are determined on Sheet 7

NSTAR Electric Company

Investment Base

Service Year Ended December 31, xxxx

Sheet 3

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Tariff				**Allocations**	
						LNS	
Line	**Description**	**Section**	**Total**	**Allocator**	**Factor**	**Amount**	**Reference**
1	**Transmission Plant**	II.A.1.a	$ -	Direct	100.0000%	-	FF1: Page 207.58(g)
2	General Plant		-	W&S	0.0000%	-	FF1: Page 207.99(g)
3	Intangible Plant		-	W&S	0.0000%	-	FF1: Page 205.5(g)
4	**Total Intangible & General Plant**	II.A.1.b	-			-	Sum Lines 2 thru 3
5	**Transmission Plant Held for Future Use**	II.A.1.c	-	Direct	100.0000%	-	FF1: Page 214.10&.23(d)
6	**Transmission Related CWIP**	II.A.1.d	-	CWIP	50.0000%	-	FF1: Page 216(b) Trans only
7	**Transmission Related Dep & Amort Reserve**	II.A.1.e					
8	Transmission Accumulated Depreciation		-	Direct	100.0000%	-	FF1: Page 219.25(b)
9	General Plant Accumulated Depreciation		-	W&S	0.0000%	-	FF1: Page 219.28(b)
10	General Plant Accumulated Amortization		-	W&S	0.0000%	-	FF1: Page 200.21(c) Footnote
11	Intangible Plant Accumulated Amortization		-	W&S	0.0000%	-	FF1: Page 200.21(c) Footnote
12	Total Transmission Related Depreciation Reserve		-			-	Sum Lines 8 thru 11
13	**Transmission Accumulated Deferred Taxes**	II.A.1.f					
14	Accumulated Deferred Taxes (190)		-		0.0000%	-	Sheet 8, Line 5, col (d)
15	Accumulated Deferred Income Taxes (281)		-			-	FF1: Page 113.62(c)
16	Accumulated Deferred Taxes - Property (282)		-				FF1: Page 275.9(k)
17	Less Transition Property		-				FF1: Page 275.4(k)
18	Net Acc. Def. Income Taxes - Other Property (282)		-	Plant	0.0000%	-	Sum Lines 16 thru 17
19	Accumulated Deferred Income Taxes - Other (283)		-		0.0000%	-	Sheet 8, Line 10, col (d)
20	Total					-	Sum Lines 17 thru 19
21	**AFUDC Regulatory Liability**	II.A.1.g	-	Direct	100.00%	-	FF1: Page 278.6(f)
22	**Gain/Loss on Reacquired Debt**	II.A.1.h	-	Plant	0.0000%	-	FF1: Page 111.81(c)+113.61(c)
23	**Other Regulatory Assets**	II.A.1.i					
24	FAS 106 (182.3 & 254)		-	W&S	0.0000%	-	FF1: Page 232.1.39(f)+278.(f)
25	FAS 109 (182.3 & 254)		-				FF1: Page 232.1.29(f)
26	Less FAS 109 - Liability (182.3 & 254)		-				FF1: Page 278.2(f)
27	Net FAS 109 (182.3 & 254)		-	Plant	0.0000%	-	Sum Lines 25 thru 26
28	Total Other Regulatory Assets		-			-	Line 24 + line 27

29	**Prepayments**	II.A.1.j	-	W&S	0.0000%	-	FF1: Page 111.57(c)+ 232.2.8(f)
30	**Transmission Materials & Supplies**	II.A.1.k	-	Direct	100.0000%	-	FF1: Page 227.8(c)+227.5(c) Trans
31	**Cash Working Capital**	II.A.1.l					
32	Operation & Maintenance Expense		-	WC	12.50%	-	Sheet 1, Line 24, col (c)
33	Administrative & General Expense		-	WC	12.50%	-	Sheet 1, Line 25, col (c)
34	Transmission Support Expenses		-	WC	12.50%	-	Sheet 1, Line 28, col (c)
35	Total Cash Working Capital		-			-	Sum Lines 32 thru 33

		Allocation	
36	**Description**	**Factor**	**Reference**
37	Direct Allocation (Direct)	100.0000%	
38	Wages & Salary (W&S)	0.0000%	Sheet 6, Line 6(c)
39	Plant Allocation (Plant)	0.0000%	Sheet 6, Line 14(c)
40	Construction Work in Progress Allocation (CWIP)	50.0000%	Sheet 6, Line 15(c)
41	Cash Working Capital (WC)	12.50%	Tariff Section II.A.1.l

NSTAR Electric Company
Transmission Expenses
Service Year Ended December 31, xxxx
Sheet 4

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Tariff		**Allocations**			
Line	**Description**	**Section**	**Total**	**Allocator**	**Factor**	**LNS Amount**	**Reference**
1	**Transmission Depreciation Expense**	II.B					
2	Transmission Depreciation	II.B.i		Direct	100.00%	$ -	FF1: Page 336.7(f)
3	General Plant Depreciation and Amortization	II.B.ii		W&S	0.00%	-	FF1: Page 336.10(f)
4	Amortization of Transmission Related Intangible Plant			W&S	0.00%	-	FF1: Page 336.1(f)
5	Amortization of AFUDC Regulatory Credit		-			-	FF1: Page 278.6(d) (amort)
6	Net Amortization of Transmission Related Intangible Plant		-			-	Sum Lines 4 and 5
7	Total Transmission Depreciation Expense		$ -			$ -	Sum Lines 2, 3 and 6
8	**Amortization of Gain/Loss on Reacquired Debt**	II.C		Plant	0.00%	$ -	FF1: Page 117.64c
9	**Transmission Related Amortization of ITC**	II.D		Plant	0.00%	$ -	FF1: Page 114.19(c)
10	**Transmission Related Municipal Tax Expense**	II.E		Plant	0.00%	$ -	FF1: Page 263.5(i)
11	**Transmission Related Payroll Tax Expense**	II.F		W&S	0.00%	$ -	FF1: Page 263.8i
12	**Transmission Operation and Maintenance Expense**	II.G					
13	Operation Supervision & Engineering (560)			Direct	100.00%	$ -	FF1: Page 321.83(b)
14	Load Dispatching (561)		-	Internal Costs		-	FF1: Page 321.83(b)
15	Load Dispatch - Reliability (561.1)		-	Internal Costs		-	FF1: Page 321.85(b) footnote
16	Load Dispatch-Mon and Oper Trans System (561.2)		-	Internal Costs		-	FF1: Page 321.86(b) footnote
17	Load Dispatch-Trans Service and Scheduling (561.3)		-	Internal Costs		-	FF1: Page 321.87(b) footnote
18	Scheduling, System Control and Dispatch Services (561.4)		-	Internal Costs		-	FF1: Page 321.88(b) footnote

19	Reliability, Planning and Standards Development (561.5)		-	Internal Costs		-	FF1: Page 321.89(b)
20	Transmission Service Studies (561.6)		-	Internal Costs		-	FF1: Page 321.90(b)
21	Generation Interconnection Studies (561.7)		-	Internal Costs		-	FF1: Page 321.91(b)
22	Reliability, Planning and Standards Development (561.8)		-	Internal Costs		-	FF1: Page 321.92(b) footnote
23	Station Expenses (562)		-	Direct	100.00%	-	FF1: Page 321.93(b)
24	Overhead Lines Expenses (563)		-	Direct	100.00%	-	FF1: Page 321.94(b)
25	Underground Lines Expenses (564)		-	Direct	100.00%	-	FF1: Page 321.95(b)
26	Miscellaneous Transmission Expenses (566)		-	Direct	100.00%	-	FF1: Page 321.97(b)
27	Rents (567)		-	Direct	0.00%	-	Sheet 5, Line 7, col (d)
28	Transmission Maintenance (568 - 573)		-	Direct	100.00%	-	FF1: Ppage 321.111(b)
29	Regional Market Expense (575)		-	Internal Costs	0.00%	-	FF1: Ppage 322.131(b)
30	Total Transmission O&M Expense		$ -			$ -	Sum Lines 13 thru 28
31	**Transmission Related A&G Expenses**	II.H					
32	Administrative and General Expenses		$0				FF1: Page 323.197(b)
33	Property Insurance (924)		-				FF1: Page 323.185(b)
34	Employee Pension and Benefits (926)		-				FF1: Page 323.187(b)
35	Regulatory Commission Expense (928)		-				FF1: Page 323.189(b)
36	General Advertising Expense (930.1)		-				FF1: Page 323.191(b)
37	Merger Related Costs		-				FF1: Page 320 FN
38	Sub-Total		-	W&S	0.00%	-	Sum Lines 32 thru 37
39	Property Insurance (924)	II.H.2	-	Plant	0.00%	-	Line 33
40	Employee Pension and Benefits (926) - Note 1	II.H.1	-	W&S	0.00%	-	Line 34
41	Regulatory Commission Expense (928)	II.H.3	-	Footnote	0.00%	-	Line 59
42	General Advertising Expense (930.1)	II.H	-		0.00%	-	Line 36
43	Transmission Merger Related Costs		-	Direct	100.00%	-	FF1: Page 320 FN
44	Total Transmission Related A&G Expenses		$ -			$ -	Sum Lines 39 thru 43
45	Regulatory Commission Expense (928)	II.H.3					
46	DPU - General Assessment		$ -		0.00%	$ -	FF1: Page 350.1 (d)
47	DPU - Appropriation Account		-		0.00%	-	FF1: Page 350.2 (d)
48	DPU - AGO Assessment #1		-		0.00%	-	FF1: Page 350.3 (d)

49	DPU - AGO Assessment #2		-		0.00%	-	FF1: Page 350.4 (d)
50	DPU - Outage Reporting Assessment		-		0.00%	-	FF1: Page 350.5 (d)
51	DPU - Manhole Cover Assessment		-		0.00%	-	FF1: Page 350.6 (d)
52	DPU - Stray Voltage Assessment		-		0.00%	-	FF1: Page 350.7 (d)
53	MA Emergency Management Agency		-		0.00%	-	FF1: Page 350.8 (d)
54	FERC Assessment		-	Direct	100.00%	-	FF1: Page 350.9 (d)
55	FER LICAP Docket		-	Direct	100.00%	-	FF1: Page 350.10 (d)
56	FERC RMR Docket		-	Direct	100.00%	-	FF1: Page 350.11 (d)
57	FERC Docket ER07-549, Including cost of audit		-	Direct	100.00%	-	FF1: Page 350.12 (d)
58	DPU Regulatory Proceeding Costs 05-85		-		0.00%	-	FF1: Page 350.13 (d)
59	Total Regulatory Commission Expenses	II.H.3	-		0.00%	-	Sum Lines 46 thru 58

	Description	Allocation Factor	Reference
60	Direct Allocation (Direct)	100.0000%	
61	Wages & Salaries Allocation (W&S)	0.0000%	Sheet 6, Line 6(c)
62	Plant Allocation (Plant)	0.0000%	Sheet 6, Line 14(c)

63 **Note 1**

64 Included in the Employee Pension and Benefits Expenses are costs related to Post Retirement Benefits other than Pension (PBOP). PBOP costs are determined

65 by an independent actuary as required by FASB 106. The PBOP expense included in Account 926 for 20xx was $xx,xxx,xxx as compared to $xx,xxx,xxx in the prior year;

66 as shown

67 on the FF1, Page 323, footnote. Applying the labor allocator to the total PBOP expense results in $x,xxx,xxx of PBOP expense being recovered through the LNS Tariff

68 in 20xx as compared to $x,xxx,xxx in the prior year.

NSTAR Electric Company

Support Expense & Revenue Detail

Service Year Ended December 31, xxxx

Sheet 5

	(a)	(b)	(c)	(d)	(e)
Line	Description	Tariff Section	Amount	Includable Amount	Reference
1	Transmission Rents (Account 567)	II.G			
2	Hydro Quebec DC Phase I Support			-	FF1: Page 320.98 (b) Footnote
3	Hydro Quebec DC Phase II Support			-	FF1: Page 320.98 (b) Footnote
4	New England Power Support			-	FF1: Page 320.98 (b) Footnote
5	Hydro Quebec Phase II NEP AC, Chester SVC			-	FF1: Page 320.98 (b) Footnote
6	Transmission Line Rents		-	-	FF1: Page 320.98 (b) Footnote
7	Total Transmission Rents Received		-	-	Sum Lines 2 thru 6
8	Transmission Related Integrated Facilities Charges	II.I	-	-	
9	- none -		-	-	
10	Total Trans Related Integrated Facilities Charges		-	-	Sum Lines 9 thru 9
11	Transmission Support Revenues 456 & 456.1	II.J			
12	Item #1			$ -	FF1: Page 300.21(b) Footnote
13	Item # 2			-	FF1: Page 300.21(b) Footnote
14	Last Item		-	-	FF1: Page 300.22(b) Footnote
15	Total Short Term & Non-Firm PTP Revenues		$ -	$ -	Sum Lines 12 thru 14
16	Transmission Support Expense (565)	II.K			
17	Item #1			-	FF1 Q2: Page 332.2(h)
18	Item # 2			-	FF1 Q3: Page 332.2(h)
19	Last Item		-	-	FF1: Page 332.2(h)
20	Total Transmission Support Expense		-	-	Sum Lines 17 thru 19
21	Transmission Related Expense from Generators	II.L			N/A
22	- none -		-	-	
23	Total Trans Related Expense from Generators		-	-	Sum Lines 22 thru 22
24	Rents Received from Electric Property (454)	II.M			
25	Item #1			-	FF1: Page 300.19(b) Footnote
26	Item # 2			-	FF1: Page 300.19(b) Footnote
27	Last Item		-	-	FF1: Page 300.19(b) Footnote
28	Total Rents Received		-	-	Sum Lines 25 thru 27
29	Short-Term and Non-Firm Point-to-Point Rev	II.N	$ -	$ -	N/A
30	- none -		-	-	
31	Total ST and Non-Firm Point-to-Point Revenues		-	-	Sum Lines 30 thru 30
32	Regional Network Service Revenues (456):	II.O			
33	RNS Transmission Revenue		-	-	
34	RNS PTF Post 2003 investment 1 % Adder		-	-	RNS Revenue Requirement
35	RNS PTF RTO Participation 0.5% Adder		-	-	RNS Revenue Requirement

36	Total Regional Network Services Revenues			-	-	Sum Lines 33 thru 35
37	Through or Out Revenues	II.P	$	-	$ -	N/A
38	- none -			-	-	
39	Total Through or Out Revenue			-	-	Sum Lines 38 thru 38
40	ISO-NE Scheduling & Dispatch Revenue	II.Q				
41	Nepool Scheduling & Dispatch Revenue			-	-	
42	RTO Participation 0.5% Adder			-	-	Reguional Schedule 1 Revenue Requirement
43	Total ISO-NE Scheduling & Dispatch Revenue			-	-	Sum Lines 42 thru 42

NSTAR Electric Company

Allocation Factors

Service Year Ended December 31, xxxx

Sheet 6

	(a)	(b)	(c)	(d)
		Tariff		
Line	**Description**	**Section**	**Amount**	**Reference**
	Transmission Wages & Salaries Allocation			
1	**Factor**	I.A.1		
2	Transmission Related Direct Wages & Salaries		$ -	FF1: Page 354.21(b)
3	Total Direct Wages & Salaries		-	FF1: Page 354.28(b)
4	Administrative & General Wages & Salaries		-	FF1: Page 354.27(b)
5	Net Total Direct Wages & Salaries		-	Line 3 less Line 4
6	Transmission Wages & Salaries Allocation Factor		**0.0000%**	Line 2 / Line 5
7	**Plant Allocation Factor**	I.A.2		
8	Transmission Plant Investment		$ -	FF1: Page 207.58(g)
9	HQ Leases		-	
10	Transmission Related General Plant		-	Sheet 3, Line 2, Col (f)
11	Transmission Related Intangible Plant		-	Sheet 3, Line 3, Col (f)
12	Total Transmission Plant Investment		-	Sum Lines 8 thru 11
13	Total Plant in Service		-	FF1: Page 207.104(g)
14	Plant Allocation Factor		**0.0000%**	Line 12 / Line 13

15	**Construction Work in Progress Allocation Factor**	II.A.1.d	**50.0000%**

NSTAR Electric Company

Cost of Long Term Debt

Service Year Ended December 31, xxxx

Sheet 7

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	FF1:256(a)	FF1:256(d)		FF1:256(e)	FF1:256(b)	FF1:256(h)		FF1:256(c)					
		Long Term Debt				Principal		Debt	Call				
			Term	Coupon	Original	Amount	Percent	Disc &	Premium on	Net	Cost to	Weighted	
Line	Series	Dated	(Years)	Rate	Issue	Outstanding	of Total	Exp	Debt	Proceeds	Maturity	Cost	Reference
							Col f / Col f Total			**Col f - Col h - Col i**	**Col d + ((Col h + Col i) / (Col e / Col d))**	Col h * Col g	
1	MIFA Bonds	2/8/94	20	5.75%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
2	4.875% Debentures	4/13/04	10	4.875%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
3	7.8% Debentures	5/10/95	15	7.80%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
4	4.875 Debentures	10/9/02	10	4.875%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
5	5.75% Debentures	3/13/06	30	5.750%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
6	5.625% Debentures	11/19/07	10	5.63%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
7	Total				$ -	$ -	0.00%	$ -	$ -	$ -		0.0000%	Sum Lines 1 Thru 6

Cost of Preferred Stock

Line	Series	Dated	Term	Coupon Rate	Original Issue	Principal Amount Outstanding	Percent of Total	Weighted Cost	Reference
	FF1:250(a)	Preferred Stock		FF1:250(a)		FF1:250(f)			
8	4.25%	6/13/1956	N/A	4.25%			0	0.0000%	FF1: Page 250 & 251
9	4.78%	7/10/1958	N/A	4.78%			0	0.0000%	FF1: Page 250 & 251
10 Total					$ -	$ -	0.00%	0.0000%	Sum Lines 8 Thru 9

Effective NSTAR ROI

Tariff Section II.A.2.a

Line	Description	Common	Preferred	LTD	Total	Reference
	(a)	(b)	(c)	(d)	(e)	(f)
11	Amount			$	-	Sheet 2, lines 2 thru 4
12	Cost	0.0000%	0.0000%	0.0000%		See Note
13	Actual Weighting	0.0000%	0.0000%	0.0000%	0.0000%	Line 11 / Total Line 11
14	Weighted Cost	0.0000%	0.0000%	0.0000%	0.0000%	Line 12 * Line 13
15	70% of Weighted Cost	0.0000%	0.0000%	0.0000%		Line 14 * 70%
16	Tariff Weighting	50.0000%	0.0000%	50.0000%	100.0000%	Tariff Section II.A.2.a
17	Weighted Cost	0.0000%	0.0000%	0.0000%	0.0000%	Line 12 * Line 16
18	30% of Weighted Cost	0.0000%	0.0000%	0.0000%		Line 17 * 30%
19	Blended Cost of Capital	0.0000%	0.0000%	0.0000%	0.0000%	Line 15 + Line 18

20	**Lower of Blended or Actual**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	Lower of line 14, col (e) or line 19, col (e)
						Tariff Section II.A.2.a

21 Note:

22 The Regurn on Equity component is specified in Tariff Section II.A.2.a.iii

23 The Cost of Preferred Stock is calculated on line 10

24 The Cost of Long Term Debt is calculated on line 7

NSTAR Electric Company

Annual Local Network Service Revenue Requirement

Service Year Ended December 31, xxxx

Sheet 8

Transmission Related ADIT - Tariff Section II.A.1.f

	(a)	(b)	(c)	(d)	(e)
Line	Description	Amount	Allocator	Rate Base	Notes
1	**Account 190**				
2	Item # 1		0.0000%	$ -	FF1: Page 234.2(c) Footnote
3	Item #2		0.0000%	-	FF1: Page 234.2(c) Footnote
4	Last Item	-	0.0000%	-	FF1: Page 234.2(c) Footnote
5	Total 190	$ -	0.0000%	$ -	Sum Lines 2 thru 4
6	**Account 283**				
7	Item # 1		0.0000%	-	FF1: Page 276.3(k) Footnote
8	Item #2		0.0000%	-	FF1: Page 276.3(k) Footnote
9	Last Item	-	0.0000%	-	FF1: Page 276.3(k) Footnote
10	Total 283	$ -	0.0000%	$ -	Sum Lines 7 thru 9
11	Wages & Salary Allocator	0.0000%			Sheet 6, Line 6, Col (d)
12	Plant Allocator	0.0000%			Sheet 6, Line 14, Col (d)

ATTACHMENT L

CREDITWORTHINESS POLICY

I. General Information:

This Attachment L details the specific requirements for the creditworthiness procedures of NSTAR. All customers taking (i) any service under Schedule 21-NSTAR or (ii) any FERC-regulated interconnection service from NSTAR must meet the terms of this Policy (where all the above, collectively, are referred to as “Services”). The creditworthiness of each customer must be established prior to receiving service from NSTAR. A customer will be evaluated at the time its application for service is provided to NSTAR. A credit review shall be conducted for each transmission customer not less than annually or upon reasonable request by the transmission customer. This Attachment L, when updated, will be done so in accordance with Section 10 of this Policy and as posted on NSTAR’s OASIS.

All customers must comply with the terms of this Attachment L. Each customer should refer to NSTAR’s web site at www.nstar.com, or NSTAR’s OASIS site, for the NSTAR representative to whom to forward the information required by this Attachment L.

Upon receipt of a customer’s information, NSTAR will review it for completeness and will notify the customer if additional information is required. Upon completion of an evaluation of a customer, NSTAR will notify the customer of its Financial Assurance requirements. NSTAR will provide a written evaluation, upon request, to customers who are not required to provide Financial Assurance.

II. Financial Information:

Customers receiving transmission service or requesting interconnection service must submit, if available, the following:

- All current rating agency reports from Standard and Poor’s (“S&P”), Moody’s and/or Fitch of the customer.
- Audited financial statements provided by a registered independent auditor for the two most recent years, or the period of its existence, if shorter, for the customer.

III. Creditworthiness Requirements:

A. The customer must meet at least one of the following quantitative criteria in order to receive unsecured credit equivalent to 3 months of transmission charges or, for interconnections, the credit equivalent of 3 months of the annual facilities charges and other ongoing charges:

i) If rated, the customer must have either for itself or for its outstanding debt the following:

- Standard and Poor's or Fitch rating of at least a BBB, or
- Moody's rating of at least a Baa2.

ii) If un-rated or if rated below BBB/Baa2, as stated in a), the customer must meet all of the following:

- A Current Ratio of at least 1.0 times (current assets divided by all current liabilities);
- A Total Capitalization Ratio of less that 60% debt: total debt (including all short-term borrowing) divided by total shareholders' equity plus total debt;
- "Earnings before interest, taxes, depreciation and amortization" in most recent fiscal quarter divided by expense for interest" (EBITDA-to-Interest Expense Ratio) of at least 2.0 times; and
- Audited Financial Statement with an unqualified audit opinion.

iii) If the customer relies on the creditworthiness of a parent company, the customer's parent company must meet the criteria set out in (a) or (b) above, and must provide to NSTAR a written guarantee that it will be unconditionally responsible for all financial obligations associated with the customer's receipt of transmission service from NSTAR.

iv) If the customer is a municipal that is a member of the Massachusetts Municipals Wholesale Electric Cooperative (MMWEC), MMWEC must meet the criteria set out in (a) or (b) above and provide to NSTAR a written guarantee that MMWEC will be unconditionally responsible for all financial obligations associated with the customer's receipt of transmission service from NSTAR.

B. If the customer does not qualify for unsecured credit under Section A, the customer will qualify

for unsecured credit equivalent to two months of transmission service charges, or for interconnections, the credit equivalent of two months of the annual facilities charges and other ongoing charges, if one of the following qualitative factors is met:

? The customer has, on a rolling basis, 12 consecutive months of payments to NSTAR with no missed, late or defaults in payment; or

? The customer has an executed long-term contract for the sale of the full output (energy and capacity) of its generating unit and either has executed a corresponding service agreement under Schedule 21-NSTAR for the transmission of that output or the execution of such a service agreement is pending the customer's demonstration of creditworthiness pursuant to this Attachment L.

IV. Financial Assurance:

If the customer does not meet the applicable requirements for Creditworthiness set out in Section III above, then the customer must either:

- Pay in advance for service an amount equal to the lesser of the total charge for Transmission Service or the charge for three months of Transmission Service not less than 5 days in advance of the commencement of service; or

- Obtain Financial Assurance in the form of a: letter of credit, performance bond, or corporate guarantee equal to the equivalent of 3 months of Transmission Service charges prior to receiving service.

If the customer pays for service in advance, NSTAR will pay to the customer interest on the amounts not yet due to NSTAR , computed in accordance with the Commission's regulations at 18 CFR ? 35.19a(a)(2)(iii).

V. Contesting Creditworthiness Determination:

The Transmission Customer may contest NSTAR's determination of creditworthiness by submitting a written request for re-evaluation within 20 calendar days of being notified of the creditworthiness determination. Such request should provide information supporting the basis for a request to re-evaluate a

Transmission Customer's creditworthiness. NSTAR will review and respond to the request within 20 calendar days.

VI. Process for Changing Credit Requirements:

In the event that NSTAR plans to revise its requirements for credit levels or collateral requirements as detailed in this Attachment L, NSTAR shall submit such changes in a filing to the Commission under Section 205 of the Federal Power Act. NSTAR shall follow the notification requirements pursuant to Section 3.04(a) of the Transmission Operating Agreement and reflected herein.

A. General Notification Process

i) NSTAR shall provide written notification to ISO-NE and stakeholders of any filing described above, at least 30 days in advance of such filing.

ii) Filing notifications shall include a detailed description of the filing, including a redlined document containing revised change(s).

iii) NSTAR shall consult with interested stakeholders upon request.

iv) Following Commission acceptance of such filing and upon the effective date, NSTAR shall revise Attachment L and an updated version of Schedule 21-NSTAR shall be posted the ISO-NE website.

B. Transmission Customer Responsibility

When there is a change in requirements pursuant to this Attachment L, it is the responsibility of the customers to forward updated financial information to NSTAR at the address noted on NSTAR's OASIS site and indicate whether the change affects their ability to meet the requirements of this Attachment L. In such cases where the customer's status has changed, the customer must take the necessary steps to comply with the revised requirements of the Attachment L by the effective date of the change.

VII. Posting Collateral Requirements:

A. Changes in Customer's Financial Condition

Each customer must inform NSTAR, in writing, within five (5) business days of any material change in its financial condition, and, if the customer qualifies under Section III.A(c), that of its parent company. A material change in financial condition may include, but is not limited to, the following:

- Change in ownership by way of a merger, acquisition or substantial sale of assets;
- A downgrade of long- or short-term debt rating by a major rating agency;
- Being placed on a credit watch with negative implications by a major rating agency;
- A bankruptcy filing;
- Any action requiring filing of a Form 8-K;
- A declaration of or acknowledgement of insolvency;
- A report of a significant quarterly loss or decline in earnings;
- The resignation of key officer(s);
- The issuance of a regulatory order and/or the filing of a lawsuit that could materially adversely impact current or future financial results.

B. Change in Creditworthiness Status

- A customer who has been extended unsecured credit under this policy must comply with the terms of Financial Assurance in Section IV above if one or more of the following conditions apply:
- The customer no longer meets the applicable criteria for Creditworthiness in Section III above;
- The customer exceeds the amount of unsecured credit extended by NSTAR, in which case Financial Assurance equal to the amount of excess must be provided within 5 business days; or
- The customer has missed two or more payments for any of the services offered by NSTAR in the last 12 months.

In the event that NSTAR determines that there is a change in the credit level or collateral requirements, the customer may request a written explanation of the basis for this change. Such notification should be

sent to the NSTAR contact indicated on the NSTAR OASIS site. NSTAR shall respond to such request within 20 days of receipt of such notification.

Unless otherwise noted above, when there is a change in a customer's Creditworthiness Status requiring the customer to provide Financial Assurance, the customer must provide such Financial Assurance within 20 business days from the date the customer either notifies NSTAR, as required in Section VI.B above, or receives notice from NSTAR.

VIII. Ongoing Financial Review:

Each customer is required to submit to NSTAR annually or when issued, as applicable:

- Current rating agency report;
- Audited financial statements from a registered independent auditor; and
- 10-Ks and 8-Ks, promptly upon their issuance.

IX. Suspension of Service:

NSTAR may immediately suspend service (with notification to Commission) to a customer, and may initiate proceedings with Commission to terminate service, if the customer does not meet the terms described in Sections III through VIII above at any time during the term of service or if the customer's payment obligations to NSTAR exceed the amount of unsecured or secured credit to which it is entitled under this Attachment L. A customer is not obligated to pay for transmission service that is not provided as a result of a suspension of service.

Eversource

SCHEDULE 21-ES

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SCHEDULE 21-ES

LOCAL SERVICE SCHEDULE

This Local Service Schedule, designated Schedule 21-ES, governs the terms and conditions of service taken by Transmission Customers over the Transmission System of The Connecticut Light and Power Company, Public Service Company of New Hampshire and Western Massachusetts Electric Company (together, “Eversource”), but not over the Transmission System of their affiliate, NSTAR Electric Company, which provides service pursuant to Schedule 21-NSTAR.

I. COMMON SERVICE PROVISIONS

1 Definitions

Capitalized terms not defined herein shall have the meanings given them in the Tariff.

1.1 Annual Transmission Costs

The total annual cost of the Transmission System for purposes of Local Network Service shall be the amount specified in Attachments ES-H and ES-I, until amended by Eversource or modified by the Commission.

1.2 Annual True Up

The reconciliation to actual costs and actual loads of the estimated costs and loads costs used for billing purposes under Section 3.0 of this Local Service Schedule for any Service Year.

1.3 Category A Load Ratio Share

Ratio of a Transmission Customer's Category A Network Load to Eversource’s total load computed in accordance with Sections 16.5 and 16.6 under Part III of this Local Service Schedule and calculated on a rolling twelve month basis. Also referred to as “Load Ratio Share”.

1.4 Category B Load Ratio Share

Ratio of a Transmission Customer’s Monthly Category B Load in the Designated State or Area for a Localized Facility to the Monthly Transmission System Category B Load for such Designated State or Area, calculated in accordance with Sections 16.5 and 16.6, and calculated on a rolling twelve month basis.

1.5 Designated Agent

See Tariff. Also, the Designated Agent of Eversource is Eversource Energy Service Company ("Eversource Service") which is a subsidiary of Eversource Energy.

1.6 Designated State or Area

The state or area to which the Commission allocates the costs of a Localized Facility identified in Section 16.3.

1.7 **Interest**

The amount computed in accordance with the Commission's regulations at 18 CFR §35.19a (a)(2)(iii). Interest on deposits and shall be calculated from the day the deposit check is credited to Eversource's account.

1.8 **Interruption**

A reduction in non-firm transmission service due to economic reasons pursuant to Schedule 21.

1.9 **Localized** Facility

Facility or costs that the New England System Operator determines should not be included in Attachment F of the ISO OATT.

1.10 **Network Load**

The load that a Network Customer designates for Local Network Service. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements for any Point-To-Point Transmission Service that may be necessary for such non-designated load.

1.11 **Network Operating Agreement**

An executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Local Network Service under Part III of this Local Service Schedule.

1.12 **Network Upgrades**

Modifications or additions to transmission-related facilities that are integrated with and support Eversource's overall Transmission System for the general benefit of all users of such Transmission System.

1.13 **New England System Operator**

ISO New England Inc. ("ISO") or its successor entity.

1.14 **Party(ies)**

Eversource and the Transmission Customer receiving service under the Tariff.

1.15 **Short-Term Firm Point-To-Point Transmission Service**

Firm Point-To-Point Transmission Service with a term of less than one year.

1.16 Service Agreement

Service Agreement is a transmission service agreement for transmission service provided under this Local Service Schedule or Localized Costs Responsibility Agreement ("LCRA").

1.17 **Service Year**

The calendar year in which the Transmission Customer is receiving service under this Local Service Schedule.

1.18 **Eversource**

The Connecticut Light and Power Company, Western Massachusetts Electric Company, and Public Service Company of New Hampshire, each an operating company of Eversource Energy, but excluding their affiliate NSTAR Electric Company, which provides Transmission Service pursuant to Schedule 21-NSTAR.

1.19 **Eversource's Monthly Transmission System Peak**

The maximum firm usage of the Eversource Transmission System in a calendar month (this does not include load of Eversource's customers exclusively connected to PTF).

1.20 **Eversource Transmission System**

The PTF and non-PTF facilities owned, controlled or operated by Eversource that are used to provide transmission service under this Local Service Schedule. This includes PTF facilities whose costs are not included in the regional rate.

1.21 **Transmission Service**

Point-To-Point Transmission Service provided under this Local Service Schedule on a firm and non-firm basis.

2. Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. Eversource is required to provide (or offer to arrange with the New England System Operator as discussed below), and the Transmission Customer is required to purchase, the following Ancillary Service (i) Scheduling, System Control and Dispatch.

The Transmission Customer serving load within the Eversource Control Area shall also obtain the following ancillary services: (i) Reactive Supply and Voltage Control from Generation Sources, (ii) Regulation and Frequency Response, (iii) Energy Imbalance, (iv) Operating Reserve - Spinning, and (v) Operating Reserve - Supplemental.

The Transmission Customer serving load within the Eversource Control Area is required to acquire the appropriate Ancillary Services, whether from the New England System Operator, Eversource, another party, or by self-supply.

The Transmission Customer may not decline Eversource's or the New England System Operator's offer of appropriate Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from Eversource.

If Eversource is unable to provide Scheduling, System Control and Dispatch, Eversource can fulfill its obligation to provide this Ancillary Service by acting as the Transmission Customer's agent to secure this Ancillary Service from the New England System Operator. The Transmission Customer may elect to (i) have Eversource act as its agent to obtain Scheduling, System Control and Dispatch, (ii) secure Scheduling, System Control and Dispatch directly from the New England System Operator, or from a third party.

Eversource or New England System Operator shall specify the rate treatment and all related terms and conditions in the event of an unauthorized use of Ancillary Services by the Transmission Customer.

The specific Ancillary Services, prices and/or compensation methods are described on the Schedule that is attached to and made a part of the Tariff. Three principal requirements apply to discounts for Ancillary Services provided by Eversource in conjunction with its provision of transmission service as follows: (1) any offer of a discount made by Eversource must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one’s wholesale merchant or an Affiliate’s use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. A discount agreed upon for an Ancillary Service must be offered for the same period to all Eligible Customers on the Eversource system.

3. Billing and Payment

3.1 **Billing Procedure**

Within a reasonable time after the first day of each month, Eversource Service shall submit an invoice to the Transmission Customer for the charges for all services furnished or costs allocated under the Tariff during the preceding month.

The invoice shall be paid by the Transmission Customer within twenty five (25) days of the date of the invoice. All payments shall be made in immediately available funds payable to Eversource Service, or by wire transfer to a bank named by Eversource Service. Billing hereunder shall be based on cost estimates made by Eversource subject to Annual True-up when actual costs for the Service Year are known. Such Annual True-up shall occur no later than six (6) months after the close of the Service Year to which the Annual True-up relates. The Annual True-up will include interest calculated in accordance with Section 35.19a of the Commission’s regulations. If the in

service date of a forecasted capital addition changes, and the impact of such change on Eversource's annual revenue requirement is ten percent or more, Eversource Service will adjust current billing to the Transmission Customer as appropriate.

3.2 Interest on Unpaid Balances

Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by Eversource Service.

3.3 Customer Default

In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to Eversource Service on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after Eversource Service notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, Eversource may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between Eversource and the Transmission Customer, Eversource will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then Eversource may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy. Neither Party shall have the right to challenge any monthly bill or to bring any court or administrative action of any kind questioning the propriety of any bill after a period of twenty four (24) months from the date the bill was due; provided, however, that in the case of a bill based on estimates, such twenty-four month period shall run from the due date of the final adjusted bill.

3.4 Transmission Customer Right to Audit

Eversource shall keep complete and accurate accounts and records with respect to its performance under this Local Service Schedule and shall maintain such data for a period of at least two (2)

years after final billing for audit by a Transmission Customer. The Transmission Customer shall provide thirty (30) days' written notice to Eversource to request an audit of all such accounts and records relevant to service provided to the Transmission Customer for a specific time period. The Transmission Customer shall have the right, during normal business hours and at its own expense, to examine, inspect and make copies of all such accounts and records relevant to service provided to the Transmission Customer at such offices where such accounts and records are maintained, insofar as may be necessary for the purpose of ascertaining the reasonableness and accuracy of all relevant data, estimates or statements of charges submitted hereunder to the Transmission Customer. The records made available to a Transmission Customer for auditing purposes hereunder shall not include information pertaining to the loads of or charges to an individual customer other than the Transmission Customer; unless the Transmission Customer requests that the Commission order that such information be made available to the Transmission Customer and the Commission so orders. Nothing in this section shall be interpreted as limiting the Transmission Customer's access to system-wide load or charge data.

3.5 Regulatory Oversight of Formula Rate

Eversource will submit to the Connecticut Public Utilities Regulatory Authority, the Massachusetts Department of Public Utilities and the New Hampshire Public Utilities Commission ("State Commissions") the following information:

(a) A copy of the New England Power Pool's ("NEPOOL's") or any successor's annual informational filing at FERC supporting the total transmission revenue requirement for New England, which contains information submitted by Eversource supporting its total transmission revenue requirement;

(b) Eversource's total transmission revenue requirement as calculated in Attachments H & I under Schedule 21-ES;

(c) A copy of Eversource's applications under Restated NEPOOL Agreement Section 15.5, concerning the installation of or material changes to transmission facilities (or any successor approval process), and Section 18.4, concerning plans for additions, retirements, or changes in the capacity of transmission facilities (including descriptions of facilities and cost estimates);

(d) A copy of ISO New England's or any successor's Regional Transmission System Plan, which contains all identified improvements to the New England power system approved by the ISO New England or any successor's board;

(e) A copy of Eversource's filing to each New England state's siting council for those projects to be recovered through the RNS or LNS rates, such copy to be filed with the State Commissions when the estimated costs of the projects in question are proposed to be included in the RNS and LNS rates;

(f) At the same time that new estimated rates are implemented, the estimated cost for each capital addition (on a project-by-project basis) the cost of which is to be included in the estimated rates; and, for each such capital addition with an estimated cost of $20 million or greater, Eversource will provide the following to the extent available: (i) a breakdown of the projected cost into the following categories: labor (broken down into planning, engineering, construction, and other), outside services (broken down into planning, engineering, construction and other), materials (broken down into station equipment, towers and poles, overhead conductor, underground conduit and conductor, and other), land (broken down into fee ownership, easement, and other), and other (if applicable) and (ii) a non-binding estimate of the total project costs by calendar quarter;

(g) Within 60 days after the true-up is rendered for a year, the actual cost for each capital addition that was placed in service during that year; and, for each such capital addition with an actual or estimated cost of $20 million or greater, Eversource will provide the following to the extent available: (i) a breakdown of the actual cost into the following categories: labor (broken down into planning, engineering, construction, and other), outside services (broken down into planning, engineering, construction, and other), materials (broken down into station equipment, towers and poles, overhead conductor, underground conduit and conductor, and other), land (broken down into fee ownership, easement, and other), and other (if applicable) and (ii) the actual total project costs by calendar quarter.

4. Regulatory Filings

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the right of Eversource to unilaterally make application to the Commission for a change in rates, terms and

conditions, charges, classification of service, Service Agreement, rule or regulation under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the ability of any Party receiving service under the Tariff to exercise its rights under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

5. Creditworthiness: See Attachment ES-L to this Schedule 21-ES.

6. Rights Under The Federal Power Act

Nothing in this section shall restrict the rights of any party to file a complaint with the Commission under relevant provisions of the Federal Power Act.

II. POINT-TO-POINT TRANSMISSION SERVICE

Scheduling of Point-To-Point Transmission Service:

The System Operator will dispatch all resources subject to its control, pursuant to Market Rule 1, in order to meet load and to accommodate external transactions. Resources within the New England Control Area using Firm Point-to-Point Transmission Service shall be dispatched based on economic merit in accordance with Market Rule 1 and will have no physical scheduling or dispatch rights. Transmission Customers will be charged for congestion costs and any other costs associated with such dispatch in accordance with Market Rule 1.

7. Nature of Firm Point-To-Point Transmission Service

7.1 Classification of Firm Transmission Service

The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedule ES-2, as appropriate, for Long and Short-Term Firm Point-To-Point Transmission Service. In the event that either a Transmission Customer has not made a capacity reservation, or a Transmission Customer exceeds its firm capacity reservation at the Point of Receipt and Point of Delivery the Transmission Customer shall be billed and pay for its actual use of such excess capacity in addition to any Reserved Capacity pursuant to Schedule ES-2, including ancillary services provided pursuant to Schedule ES-1 hereto.

8. Nature of Non-Firm Point-To-Point Transmission Service

8.1 Classification of Non-Firm Point-To-Point Transmission Service

The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedule ES-3, as appropriate, for non-firm Point-To-Point Transmission Service. In the event that either a Transmission Customer has not made a capacity reservation, or a Transmission Customer exceeds its non-firm capacity reservation at any Point of Receipt or Point of Delivery, the Transmission Customer shall be billed and pay for its actual use of such excess capacity in addition to any Reserved Capacity pursuant to Schedule ES-3, including ancillary services provided pursuant to Schedule ES-1 hereto. Non-Firm Point-To-Point Transmission Service shall include transmission of energy on an hourly basis and transmission of scheduled short-term capacity and/or energy on a daily, weekly or monthly basis, but not to exceed one month's reservation for any one Application, under Schedule ES-3.

9. Service Availability

9.1 Real Power Losses

Real Power Losses are associated with all transmission service. Eversource is not obligated to provide Real Power Losses. The Transmission Customer is responsible for replacing losses associated with all transmission service as determined under Market Rule 1. The applicable Real Power Loss factors are as follows:

The amount of transmission losses incurred in transmitting power from the POR(s) to the POD(s) ("Loss Amount") shall be determined from time to time by the New England System Operator in accordance with ISO procedures applicable at the time of delivery. The Loss Amounts, when determined by the New England System Operator, shall be posted on Eversource's Open Access Same-Time Information System ("OASIS"). In the event that the New England System Operator, for any reason, does not determine the entire Loss Amount, the losses not determined by the New England System Operator shall be based on average system losses as set forth below:

Cumulative Losses in Percent

POR/POD	**Peak***	**Off-Peak**	**24 Hr. Avg.**
Bulk Transmission	1.98	2.42	2.21
Bulk Substation	2.46	2.92	2.70
Pri. Distribution	4.58	4.50	4.54

*Peak hours are defined as 0700-2300, Monday-Friday; Off-Peak hours are all other hours.

10. Procedures for Arranging Firm Point-To-Point Transmission Service

10.1 Deposit

A Completed Application for Firm Point-To-Point Transmission Service also shall include a deposit of either three month's charge for Reserved Capacity or the full charge for Reserved Capacity for service requests of less than one month.

11. Additional Study Procedures For Firm Point-To-Point Transmission Service Requests:

11.1 Disbursement Methodology for Late Study Penalties

See Attachment ES-D to Schedule 21-ES.

12. Compensation for Transmission Service

The Transmission Customers taking Point-To-Point Transmission Service shall pay Eversource for any Direct Assignment Facilities, Ancillary Services and applicable study costs, along with the following:

12.1 Rates and Charges for Transmission Service

Rates for Firm and Non-Firm Point-To-Point Transmission Services are provided in the Attachments appended to this Local Service Schedule: Firm Point-To-Point Transmission Services (Schedule ES-2); and Non-Firm Point-To-Point Transmission Services (Schedule ES-3).

12.2 Rates for Firm and Non-Firm Point-To-Point Transmission Services

Rates for Firm and Non-Firm Point to Point Transmission Services shall be determined as set forth in Attachments ES-2 and ES-3 of this Local Service Schedule on the basis of estimated

costs for each Service Year until the actual costs for such Service Year are determined. Thereafter, payments made on such estimated costs shall be recalculated based on actual data for that Service Year, and an appropriate billing adjustment shall be made pursuant to Section 3 of this Local Service Schedule. Eversource shall use Part II of the Tariff to make its Third-Party Sales. Eversource shall account for such use at the applicable Tariff rates.

III. LOCAL NETWORK SERVICE

13. Nature of Local Network Service

13.1 Real Power Losses

Real Power Losses are associated with all transmission service. Eversource is not obligated to provide Real Power Losses. The Network Customer is responsible for replacing losses associated with all transmission service as determined under Market Rule 1. The applicable Real Power Loss factors are as follows:

The amount of transmission losses incurred in transmitting power across the Eversource Transmission System to the Network Customer's Network Load shall be determined from time to time by the New England System Operator in accordance with ISO procedures applicable at the time of delivery. The Loss Amounts, when determined by the New England System Operator, shall be posted on the Open Access Same-Time Information System ("OASIS"). In the event that the New England System Operator, for any reason, does not determine the entire Loss Amount, the losses not determined by the New England System Operator shall be based on average system losses as set forth below:

Cumulative Losses in Percent

POR/POD	Peak*	Off-Peak	24 Hr. Avg.
Bulk Transmission	1.98	2.42	2.21
Bulk Substation	2.46	2.92	2.70
Pri. Distribution	4.58	4.50	4.54

*Peak hours are defined as 0700-2300, Monday-Friday; Off-Peak hours are all other hours.

14. Network Resources

14.1 Use of Interface Capacity by the Network Customer

There is no limitation upon a Network Customer's use of the Eversource Transmission System at any particular interface to integrate the Network Customer's Network Resources (or substitute economy purchases) with its Network Loads. However, a Network Customer's use of Eversource's total interface capacity with other transmission systems may not exceed the Network Customer's Load.

15. Additional Study Procedures For Local Network Service Requests

15.1 Disbursement Methodology for Late Study Penalties See Attachment ES-D to Schedule 21-ES

16. Rates and Charges

The Network Customer shall pay Eversource for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following:

16.1 Rates and Charges

Rates for Local Network Service shall be determined as set forth in Schedule ES-4 on the basis of estimated costs for each Service Year until the actual costs for such Service Year are determined. Thereafter, payments made on such estimated costs shall be recalculated based on actual data for that Service Year, and an appropriate billing adjustment shall be made pursuant to Section 3 of this Local Service Schedule.

16.2 Eligible Customers Taking Service Under the ISO Tariff

Any Eligible Customer taking Regional Network Service under the ISO Tariff in a Designated State or Area shall pay to Eversource Service the customer's Category B Load Ratio Share of the Formula Requirements as calculated in Schedule ES-4, Appendix B for such Designated State or Area**.** Eversource Service shall execute a LCRA under this Local Service Schedule, in the form set forth in Attachment ES-E, to recover such charges from such customer. Eversource Service shall not bill any such customer any such costs until (1) such LCRA has been executed with the

Eligible Customer, or (2) an unexecuted LCRA has been permitted to be made effective **by** the Commission.

16.3 Listing of Localized Facilities by Designated State or Area:

(a) Connecticut:
Bethel to Norwalk Project
Middletown to Norwalk Project
Glenbrook Cables Project
Greater Springfield Reliability Project (Connecticut portion)

(b) Massachusetts:
Greater Springfield Reliability Project (Massachusetts portion)

16.4 **Monthly Demand Charge**

The Network Customer shall pay monthly Demand Charges, which shall be determined by multiplying its Category A Load Ratio Share times one twelfth (1/12) of the Formula Requirements in Schedule ES-4, Appendix A, and by multiplying its Category B Load Ratio Share for the Designated State or Area times one twelfth (1/12) of the Formula Requirements in Schedule ES-4, Appendix B for the Localized Facilities that are in such Designated State or Area.

16.5 **Determination of Network Customer's Monthly Network Load**

The Network Customer's Monthly Category A Network Load is its hourly load (including its designated Network Load not physically interconnected with Eversource under Schedule 21) coincident with Eversource's Monthly Transmission System Peak.

The Network Customer's Monthly Category B Load for a Designated State **or** Area for a Localized Facility is its hourly load in such Designated State or Area coincident with the monthly transmission system peak load for such Designated State or Area.

For Localized Facilities for which the Designated State or Area is identified as "Connecticut" in Section 16.3(a) of this Schedule 21-ES, the customer's hourly load shall be all of the customer's

Regional Network Load in Connecticut, and the monthly transmission system peak load shall be all Regional Network Load in Connecticut.

For Localized Facilities for which the Designated State or Area is identified as “Massachusetts” in Section 16.3(b) of this Schedule 21-ES, the customer’s hourly load shall be all of the customer’s Regional Network Load in Massachusetts, and the monthly transmission system peak load shall be all Regional Network Load in Massachusetts; provided, that the customer’s monthly load and the monthly transmission system peak load shall exclude the load of generators taking RNS for the delivery of offline station service.

16.6 **Determination of Eversource’s Monthly Transmission System Load**

Eversource’s Monthly Transmission System Category A Load is Eversource’s Monthly Transmission System Peak minus the coincident peak usage of all Firm Point-To-Point Transmission Service customers pursuant to this Local Service Schedule plus the Reserved Capacity of all Firm Point-To-Point Transmission Service customers.[1]

Eversource’s Monthly Transmission System Category B Load for the Designated State or Area for a **Localized** Facility is the monthly transmission system peak load for such Designated State or Area.[1]

For Localized Facilities for which the Designated State or Area is identified as “Connecticut” in Section 16.3(a) of this Schedule 21-ES, the monthly transmission system peak load shall be all Regional Network Load in Connecticut.

For Localized Facilities for which the Designated State or Area is identified as “Massachusetts” in Section 16.3(b) of this Schedule 21-ES, the monthly transmission system peak load shall be all Regional Network Load in Massachusetts; provided, that the monthly transmission system peak load shall exclude the load of generators taking RNS for the delivery of offline station service.

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1 Excludes MWs associated with lump sum payment transactions identified in footnote 2.

17. Operating Arrangements

17.1 Operation under the Network Operating Agreement

The Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Network Operating Agreement.

17.2 Network Operating Agreement

The terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Part III of the Tariff shall be specified in the Network Operating Agreement. The Network Operating Agreement shall provide for the Parties to (i) operate and maintain equipment necessary for integrating the Network Customer within the Eversource Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between Eversource and the Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside the Eversource Transmission System, interchange schedules, unit outputs for redispatch, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted loads and resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of Part III of the Tariff, including scheduling protocols. The Network Operating Agreement will recognize that the Network Customer shall either (i) operate as a Control Area under applicable guidelines of the North American Electric Reliability Council (NERC) and the Northeast Power Coordinating Council (NPCC), (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with Eversource, or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies NERC and NPCC requirements. Eversource shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services. The Network Operating Agreement is included in Attachment ES-G.

SCHEDULE ES-1

SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by Eversource (if Eversource is the Control Area operator) or indirectly by Eversource making arrangements with the New England System Operator that performs this service for the Eversource Transmission System. The Transmission Customer must purchase this service from Eversource or the New England System Operator. The charges for Scheduling, System Control and Dispatch Service are to be based on the rates set forth below. To the extent the New England System Operator performs this service for Eversource, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to Eversource by that New England System Operator.

Each Point-To-Point Transmission Customer under this Local Service Schedule will be charged for Transmission Scheduling, System Control and Dispatch Services for the total Reserved Capacity specified in each reservation for Point-To-Point Transmission Service made under this Local Service Schedule at the rates set forth in Appendix A of this Schedule ES-1. In the event that a Transmission Customer utilizes transmission capacity without a reservation or exceeds its capacity reservation at any Point of Receipt or Point of Delivery, the Transmission Customer **shall** pay for its actual use of such excess capacity in addition to any Reserved Capacity. The charge for such excess use of capacity shall be determined by multiplying the sum of the actual use in excess of its capacity reservation times the hourly non-firm rate posted on Eversource’s OASIS including ancillary services provided pursuant to Schedule ES-1 hereto.

Each Network Customer under this Local Service Schedule will be charged a monthly Transmission Scheduling, System Control and Dispatch Service Demand Charge, which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of the Formula Requirements specified in Appendix B of this Schedule ES-1.

Each Transmission Customer with generation within the New England Control Area shall be required also to provide for Scheduling, System Control and Dispatch Service for that generation. It is anticipated that the Transmission Customer will obtain these services from the ISO. Eversource will make available

Generation Scheduling, System Control and Dispatch Service at the rates set forth in Appendix C of this Schedule ES-1.

Each Transmission Customer with generation located outside of the New England Control Area shall be required to provide for Scheduling, System Control and Dispatching Service for that generation. It is anticipated that the Transmission Customer will obtain these services by contracting for these services from the provider of these services within the Control Area where the generation is located.

Eversource shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Schedule ES-1 in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE ES-1

Appendix A

POINT-TO-POINT TRANSMISSION RATE

Eversource's Formula Rate for Point-To-Point Transmission Scheduling, System Control and Dispatch Service ("Formula Rate") is an annual rate determined from the following formula.

$$\textit{Formula Rate}_i = (A_{i-1} - B_{i-1})\ C_{i-1} \text{ WHERE:}$$

- i equals the calendar year during which service is being rendered ("Service Year").

- A_{i-1} is the Annual Control Center Expenses (expressed in dollars) of Eversource for the calendar year prior to the Service Year. The Annual Control Center Expenses are determined pursuant to the formula specified in Exhibit 1 to this Appendix A of Schedule ES-1.

- B_{i-1} is the actual transmission scheduling, system control and dispatch revenues (expressed in dollars) provided from the provision of transmission services to others. The actual transmission scheduling and dispatch revenues shall be those recorded on the books of each of the companies comprising Eversource hereunder in FERC Account No. 456.1 pertaining to Transmission of Electricity for Others and such other applicable FERC accounts for the calendar year prior to the Service Year.

- C_{i-1} is the average Eversource Monthly Transmission System Category A Load (expressed in kilowatts).

SCHEDULE ES-1

Appendix A

Exhibit 1

DETERMINATION OF ANNUAL CONTROL CENTER EXPENSES

The rate formula for determination of the annual control center expenses revenue requirements for each of the companies comprising Eversource hereunder is determined as follows:

A. ANNUAL CONTROL CENTER EXPENSES

Eversource's System Control and Load Dispatching Expense, for the calendar year prior to the Service Year, as recorded in FERC Account 561.1-561.4 and the revenue requirement calculation for the CL&P Dispatch Center Plant as described in Appendix A, Exhibit 2.

SCHEDULE ES-1

APPENDIX A

EXHIBIT 2

CL&P DISPATCH CENTER REVENUE REQUIREMENT

This exhibit calculates the CL&P Dispatch Center Revenue Requirement. The CL&P Dispatch Center Revenue Requirement for use during a calendar year shall be based on CL&P's costs for the immediately preceding calendar year.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section I. of the ISO-NE Transmission, Markets and Services Tariff and as used in this exhibit have the following definitions:

Dispatch Center means CL&P's CONVEX dispatch center.

Dispatch Center Plant shall equal CL&P's year-end gross plant balances used for CL&P's Dispatch Center as recorded in FERC Account Nos. 303, 350-359, and 389-399.

Dispatch Center Depreciation Reserve shall equal CL&P's year-end depreciation reserve balance for Dispatch Center Plant as recorded in FERC Account No. 108.

Dispatch Center Accumulated Deferred Income Taxes shall equal the net of CL&P's year-end deferred tax balances for Dispatch Center Plant as recorded in FERC Account Nos. 281-283 and 190.

II. CALCULATION OF TOTAL DISPATCH CENTER REVENUE REQUIREMENT

The Dispatch Center Revenue Requirement shall equal the sum of (A) Dispatch Center Return and Associated Income Taxes, (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Amortization of Investment Tax Credits, and (D) Dispatch Center Municipal Tax Expense; provided, that during the period January 1, 2008 through December 31, 2008, the Dispatch Center Revenue Requirement shall equal the product of (i) the number of months (or fractions thereof) remaining in 2007 on and after the date upon which the CONVEX Agreements are permitted to be made effective by FERC, divided by 12 and (ii) the sum of (A) Dispatch Center Return and Associated Income Taxes, (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Amortization of Investment Tax Credits, and (D) Dispatch Center Municipal Tax Expense. "CONVEX Agreements" refers to the agreements between The

Connecticut Light & Power Company and various entities relating to the operation of the Dispatch Center and filed with FERC contemporaneously with the filing of this Exhibit 2.

A. Dispatch Center Return and Associated Income Taxes shall equal the product of the Dispatch Center Investment Base and the Cost of Capital Rate.

1. Dispatch Center Investment Base

The Dispatch Center Investment Base will be the year-end balances of: (a) Dispatch Center Plant, less (b) Dispatch Center Depreciation Reserve, less (c) Dispatch Center Accumulated Deferred Income Taxes.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) the Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon CL&P's capital structure at the end of each year and will equal the sum of (i),(ii), and (iii) below.

(i) The long-term debt component, which equals the product of the year-end balance of CL&P's first mortgage bonds and pollution control notes adjusted for premiums, discounts, debt expense and losses on reacquired debt and the ratio of the long term debt to CL&P's total capital.

(ii) The preferred stock component, which equals the product of the year-end balance of CL&P's preferred stock adjusted for premiums, discounts and unamortized issue expense and the ratio of the preferred stock to CL&P's total capital.

(iii) The common equity component, which equals the product of 10.3% and the ratio of the common equity to CL&P's total capital.

(b and c) Federal and State Income Taxes shall be computed as follows:

A x B x C

where:

A = Dispatch Center Investment Base

B = Cost of equity capital (the sum of the preferred stock component and common equity component)

C = TE / (1-TE), where TE is the effective combined federal and state statutory income tax rates in effect at the applicable time.

B. Dispatch Center Depreciation Expense shall equal CL&P's Dispatch Center depreciation expense as recorded in FERC Account No. 403.

C. Dispatch Center Amortization of Investment Tax Credits shall equal CL&P's Dispatch Center amortization of investment tax credits as recorded in FERC Account No. 411.4.

D. Dispatch Center Municipal Tax Expense shall equal CL&P's Dispatch Center municipal tax expense as recorded in FERC Account Nos. 408.1 and 409.1.

SCHEDULE ES-1

Appendix B

NETWORK TRANSMISSION FORMULA REQUIREMENTS

Eversource’s formula requirements for Network Transmission Scheduling, System Control and Dispatch Service is determined from the following formula.

Formula $\text{Requirements}_i = (A_{i\text{-}1} - B_{i\text{-}1})$

WHERE:

- i equals the calendar year during which service is being rendered ("Service Year").

- $A_{i\text{-}1}$ is the Annual Control Center Expenses (expressed in dollars) of Eversource for the calendar year prior to the Service Year. The Annual Control Center Expenses are determined pursuant to the formula specified in Exhibit 1 to this Appendix B of Schedule ES-1.

- $B_{i\text{-}1}$ is the actual transmission scheduling, system control and dispatch revenues (expressed in dollars) provided from the provision of transmission services to others. The actual transmission scheduling, system control and dispatch revenues shall be those recorded on the books of each of the companies comprising Eversource hereunder in FERC Account No. 456.1 pertaining to Transmission of Electricity for Others and such other applicable FERC Account for the calendar year prior to the Service Year.

SCHEDULE ES-1

APPENDIX B

EXHIBIT 1

DETERMINATION OF ANNUAL CONTROL CENTER EXPENSES

The rate formula for determination of the annual control center expenses for each of the companies comprising Eversource hereunder is determined as follows:

A. ANNUAL CONTROL CENTER EXPENSES

Eversource's System Control and Load Dispatching Expense), for the calendar year prior to the Service Year as recorded in FERC Account 561.1-561.4 and the revenue requirement calculation for the CL&P Dispatch Center Plant as described in Appendix B, Exhibit 2.

SCHEDULE ES-1

APPENDIX B

EXHIBIT 2

CL&P DISPATCH CENTER REVENUE REQUIREMENT

This exhibit calculates the CL&P Dispatch Center Revenue Requirement. The CL&P Dispatch Center Revenue Requirement for use during a calendar year shall be based on CL&P's costs for the immediately preceding calendar year.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section I. of the ISO-NE Transmission, Markets and Services Tariff and as used in this exhibit have the following definitions:

Dispatch Center means CL&P's CONVEX dispatch center.

Dispatch Center Plant shall equal CL&P's year-end gross plant balances used for CL&P's Dispatch Center as recorded in FERC Account Nos. 303, 350-359, and 389-399.

Dispatch Center Depreciation Reserve shall equal CL&P's year-end depreciation reserve balance for Dispatch Center Plant as recorded in FERC Account No. 108.

Dispatch Center Accumulated Deferred Income Taxes shall equal the net of CL&P's year-end deferred tax balances for Dispatch Center Plant as recorded in FERC Account Nos. 281-283 and 190.

II. CALCULATION OF TOTAL DISPATCH CENTER REVENUE REQUIREMENT

The Dispatch Center Revenue Requirement shall equal the sum of (A) Dispatch Center Return and Associated Income Taxes, (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Amortization of Investment Tax Credits, and (D) Dispatch Center Municipal Tax Expense; provided, that during the period January 1, 2008 through December 31, 2008, the Dispatch Center Revenue Requirement shall equal the product of (i) the number of months (or fractions thereof) remaining in 2007 on and after the date upon which the CONVEX Agreements are permitted to be made effective by FERC, divided by 12 and (ii) the sum of (A) Dispatch Center Return and Associated Income Taxes, (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Amortization of Investment Tax Credits, and (D) Dispatch Center Municipal Tax Expense. "CONVEX Agreements" refers to the agreements between The

Connecticut Light & Power Company and various entities relating to the operation of the Dispatch Center and filed with FERC contemporaneously with the filing of this Exhibit 2.

A. Dispatch Center Return and Associated Income Taxes shall equal the product of the Dispatch Center Investment Base and the Cost of Capital Rate.

1. Dispatch Center Investment Base

The Dispatch Center Investment Base will be the year-end balances of: (a) Dispatch Center Plant, less (b) Dispatch Center Depreciation Reserve, less (c) Dispatch Center Accumulated Deferred Income Taxes.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) the Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon CL&P's capital structure at the end of each year and will equal the sum of (i),(ii), and (iii) below.

(i) The long-term debt component, which equals the product of the year-end balance of CL&P's first mortgage bonds and pollution control notes adjusted for premiums, discounts, debt expense and losses on reacquired debt and the ratio of the long term debt to CL&P's total capital.

(ii) The preferred stock component, which equals the product of the year-end balance of CL&P's preferred stock adjusted for premiums, discounts and unamortized issue expense and the ratio of the preferred stock to CL&P's total capital.

(iii) The common equity component, which equals the product of 10.3% and the ratio of the common equity to CL&P's total capital.

(b and c) Federal and State Income Taxes shall be computed as follows:

A x B x C

where:

A = Dispatch Center Investment Base

B = Cost of equity capital (the sum of the preferred stock component and common equity component)

C = TE / (1-TE), where TE is the effective combined federal and state statutory income tax rates in effect at the applicable time.

B. Dispatch Center Depreciation Expense shall equal CL&P's Dispatch Center depreciation expense as recorded in FERC Account No. 403.

C. Dispatch Center Amortization of Investment Tax Credits shall equal CL&P's Dispatch Center amortization of investment tax credits as recorded in FERC Account No. 411.4.

D. Dispatch Center Municipal Tax Expense shall equal CL&P's Dispatch Center municipal tax expense as recorded in FERC Account Nos. 408.1 and 409.1.

SCHEDULE ES-1

Appendix C

GENERATION RATES

Eversource's Formula Rate for Generation Scheduling, System Control and Dispatch Service ("Formula Rate") shall be calculated using the Point-to-Point Formula Rate for Transmission Scheduling, System Control, and Dispatch Service in Appendix A of Schedule ES-1.

SCHEDULE ES-2

FIRM POINT-TO-POINT SERVICE

I. Each month, Eversource Service shall bill the Transmission Customer for Long-Term Firm and Short-Term Firm Transmission Service and the Transmission Customer shall be obligated to pay Eversource the charges as set forth in this Schedule ES-2, as applicable.

A. <u>TRANSMISSION CHARGES</u>

1. <u>Determination of Transmission Charges</u>

The Transmission Charges will provide for recovery of the costs of the transmission facilities ofEversource. The Category A Transmission Charges for each month will equal the sum of the Category A Charges for each monthly (or longer term), weekly or daily transaction during such month. In the event that a Transmission Customer utilizes transmission capacity without a reservation or exceeds its capacity reservation at any Point of Receipt or Point of Delivery, the Transmission Customer **shall** pay for its actual use of such excess capacity in addition to the charges for each monthly, weekly or daily transactions during such month. The charge for such excess use of capacity shall be determined by multiplying the actual hourly use in excess of its capacity reservation times the applicable Category A on-peak or off-peak hourly non-firm rate posted on Eversource’s OASIS pursuant to Schedule ES-3 including ancillary services provided pursuant to Schedule ES-1 hereto.

The Category A Charge for each monthly (or longer term) transactions will be the product of: (a) Eversource’s Category A Formula Rate (expressed in $ per kilowatt-year), divided by twelve (12) months, and (b) the Reserved Capacity set forth for such monthly (or longer term) transaction (expressed in kilowatts).

The Category A Charge for each weekly transaction will be the product of: (a) Eversource’s Weekly Category A Short-Term Firm Point-To-Point Transmission Rate (expressed in $ per kilowatt-week), and (b) the Reserved Capacity set forth for such weekly transaction (expressed in kilowatts). Eversource’s Weekly Category A Rate is Eversource’s Category A Formula Rate for Firm Point-To-Point Transmission Service divided by fifty-two (52) weeks.

The Category A Charge for each daily transaction will be the product of: (a) Eversource's Daily Category A Short-Term Firm Point-To-Point Transmission Rate (expressed in $ per kilowatt-day), and (b) the Reserved Capacity set forth for such daily transaction (expressed in kilowatts). Eversource's Daily Category A Rate is Eversource's Weekly Category A Rate for Short-Term Firm Point-To-Point Transmission Service divided by five (5) days. The total of the Transmission Customer's charges for daily transactions, under an individual reservation, in a seven (7) day period shall not exceed the charges based on the Weekly Category A Rate and the Transmission Customer's maximum Reserved Capacity in the period.

2. Eversource's Formula Rates

Eversource's Formula Rates for Long-Term Firm and Short-Term Firm Point-To-Point Service shall be determined in accordance with the rate formulas specified in Appendix A of this Schedule ES-2.

3. Tax Rates and Taxes

Eversource's Formula Rates set forth in this schedule in effect during a Service Year shall be based on the local, state, and federal tax rates and taxes in effect during the Service Year. If, at any time, additional or new taxes are imposed on Eversource or existing taxes are removed, Eversource's Formula Rate will be appropriately modified and filed with the Commission in accordance with Part 35 of the Commission's regulations.

4. Provision re: Exchanges

With respect to Entitlement Transactions or Energy Transactions or other transactions that involve an exchange, each party to such transaction shall be treated as an individual Transmission Customer under this Local Service Schedule. Accordingly, a separate Schedule ES-2 or other

applicable charge(s) will be calculated for, and a separate bill will be rendered to, each such individual Transmission Customer.

5. Discounts

Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by Eversource must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, Eversource must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

6. Resales

The rates and rules governing charges and discounts in Sections I.A.1 and 5 of this Schedule ES-2 stated above shall not apply to resales of transmission service, compensation for which shall be governed by Schedule 21.

II. In addition to the applicable charges of this Local Service Schedule, and as otherwise specified in the Service Agreement, the Transmission Customer shall pay to Eversource Service each month the following additional charges for Long-Term, and Short-Term Firm Point-To-Point Transmission Service provided during such month.

A. Taxes and Fees Charge

B. Regulatory Expenses Charge

C. Other

A. **TAXES AND FEES CHARGE**

If any governmental authority requires the payment of any fee or assessment or imposes any form of tax with respect to payments made for Long-Term Firm or Short Term Firm Point-To-Point Transmission Service provided under this Local Service Schedule, not specifically provided for in any of the charge or

rate provisions under this Local Service Schedule, including any applicable interest charged on any deficiency assessment made by the taxing authority, together with any further tax on such payments, the obligation to make payment for any such fee, assessment, or tax shall be borne by the Transmission Customer. Eversource will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's regulations.

B. **REGULATORY EXPENSES CHARGE**

Eversource shall have the right to make a Section 205 filing for recovery of regulatory expenses associated with this Local Service Schedule and the Service Agreements.

C. **OTHER**

Eversource shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Schedule ES-2 in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE ES-2

Appendix A

CATEGORY A RATE

FIRM POINT-TO-POINT TRANSMISSION SERVICE

Eversource’s Category A Formula Rate for Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service ("Formula Rate") is an annual rate determined from the following formula.

Formula $\text{Rate}_i = (A_i - B_i + C_i - D_i) / E_i$

WHERE:

- i equals the Service Year.

- A is the annual Total Transmission Revenue Requirements (expressed in dollars) as described in Attachment ES-H,

- B is the revenues received (expressed in dollars) from the provision of transmission and other related services, to others as recorded in FERC Accounts 456.1 and 454 to the extent that such transactions are not included in the determination of load (E),[2] minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

- C is the transmission payments (expressed in dollars) to the New England System Operator as recorded in FERC Account 565 in accordance with the Tariff.

- D is the sum of the annual revenues received (expressed in dollars) for the costs associated with the Localized Facilities, minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

- E is the average Eversource Monthly Transmission System Category A Load (expressed in kilowatts).

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[2] Includes amortization of revenues from point-to-point transmission service provided to Consolidated Edison Energy Massachusetts, Inc. and NRG Energy, Inc. under contracts in which customers paid based on single lump sum payment.

SCHEDULE ES-2

[Reserved]

SCHEDULE ES-3

NON-FIRM POINT-TO-POINT SERVICE

I. Eversource shall bill the Transmission Customer for Non-Firm Point-To-Point Transmission Service, and the Transmission Customer shall be obligated to pay Eversource the charges as set forth in this Schedule ES-3 as applicable.

A. **TRANSMISSION CHARGES**

1. General

The Transmission Customer shall pay to Eversource Service each month the Category A Transmission Charges calculated for all of the Transmission Customer’s monthly transactions, weekly transactions, daily transactions and hourly transactions, each as set forth below. In the event that a Transmission Customer utilizes transmission capacity without a reservation or exceeds its capacity reservation at any Point of Receipt or Point of Delivery, the Transmission Customer shall pay for its actual use of such excess capacity in addition to the charges for each monthly, weekly, daily or hourly transactions during such month. The charge for such excess use of capacity shall be determined by multiplying the actual hourly use in excess of its capacity reservation times the applicable Category A on-peak or off-peak hourly non-firm rate posted on Eversource’s OASIS pursuant to this Schedule ES-3 including ancillary services provided pursuant to Schedule ES-1 hereto.

With respect to any wholesale transactions that involve an exchange, each party to such transaction shall be an individual Transmission Customer under this Local Service Schedule. Accordingly, a Transmission Charge, as applicable, will be calculated for, and a separate bill will be rendered to, each such Transmission Customer.

The Category A Transmission Charge for each month applicable to a monthly transaction shall be determined as the product of: (a) the Category A rate posted on Eversource’s Open Access Same-Time Information System ("OASIS") at the time the service is reserved, not to exceed Eversource’s Annual Category A Rate for Non Firm Point-To-Point Transmission Service divided by twelve (12) months and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Reservation for such month (expressed in kilowatts).

The Category A Transmission Charge for each month applicable to weekly transactions shall be the sum of the transmission charges determined for each weekly transaction during such month. The transmission charge for each weekly transaction shall be determined as the product of: (a) the Category A rate posted on Eversource's OASIS at the time the service is reserved, not to exceed Eversource's Weekly Category A Firm Point-To-Point Transmission Charge Rate (expressed in $ per kilowatt-week), and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Reservation for such week (expressed in kilowatts). Eversource's Weekly Category A Rate is Eversource's Annual Category A Rate for Non-Firm Point-To-Point Transmission Service divided by fifty-two (52) weeks.

The Transmission Charge for each month applicable to daily transactions will be the sum of the transmission charges determined for each daily transaction. The transmission charge for each daily transaction shall be determined as the product of: (a) the rate posted on Eversource's OASIS at the time the service is reserved, not to exceed Eversource's Daily Category A Firm Point-To-Point Transmission Charge Rate (expressed in $ per kilowatt-day), and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Reservation for such day (expressed in kilowatts). Eversource's Daily Category A On-Peak Rate is Eversource's Weekly Category A Rate for Non-Firm Point-To-Point Transmission Service divided by five (5) days. Eversource's Daily Category A Off-Peak Rate is Eversource's Weekly Category A Rate for Non-Firm Point-To-Point Transmission Service divided by seven (7) days. The total of the Transmission Customer's charges for daily transactions, under an individual Reservation, in a seven (7) day period shall not exceed the charges based on the Weekly Category A Rate and the Transmission Customer's maximum Reserved Capacity in the period.

The Transmission Charge for each month applicable to hourly transactions will be the sum of the transmission charges determined for each hourly transaction during such month. The transmission charge for each hour of an hourly Transaction shall be determined as the product of: (a) the rate posted on Eversource's OASIS at the time the service is reserved, not to exceed Eversource's Daily Category A Firm Point-To-Point Transmission Service Rate divided by sixteen (16) hours (expressed in $ per kilowatt-hour), and (b) the Reserved Capacity as set forth in the Transmission Customer's applicable Reservation for such hour (expressed in kilowatts). Eversource's Hourly Category A On-Peak Rate is equal to Eversource's Daily Category A Rate for Non-Firm Transmission Service divided by sixteen (16) hours. Eversource's Hourly Category A Off-Peak Rate is equal to Eversource's Daily Category A Rate for Non-Firm Transmission

Service divided by twenty-four (24) hours. The total of the Transmission Customer's charges for hourly transactions, under an individual Reservation, in a twenty-four (24) hour period shall not exceed the charges based on the Daily Category A Rate and the Transmission Customer's maximum Reserved Capacity in the period.

2. Discounts

Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by Eversource must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, Eversource must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

3. Resales

The rates and rules governing charges and discounts in Sections I.A.1 and 2 of this Schedule ES-3 stated above shall not apply to resales of transmission service, compensation for which shall be governed by Schedule 21.

4. Credit to the Transmission Charge

Whenever service provided hereunder is interrupted or curtailed by Eversource, the Local Control Center or the New England System Operator, the Transmission Charges to the Transmission Customer calculated pursuant to Section A, of this Schedule ES-3 shall be credited by an amount equal to the sum of the credits calculated for each hour of interruption or curtailment in service.

The credit to the Transmission Customer for each such hour of interruption or curtailment shall be calculated as the product of (i) the applicable equivalent hourly charge for hourly, daily, weekly, or monthly transactions, and (ii) the kilowatts of service interruption or curtailment during such hour.

5. Eversource's Annual Formula Rate for Non Firm Point-To-Point Transmission Service

Eversource's Annual Formula Rates for Non Firm Point-To-Point Transmission Service shall be expressed in $ per kilowatt-year and shall be determined in accordance with the rate formulas specified in Appendix A of this Schedule ES-3 ("Formula Rates").

6. Tax Rates and Taxes

The Formula Rates set forth in this Schedule ES-3 in effect during a Service Year shall be based on local, state, and federal tax rates and taxes in effect during the Service Year. If, at any time, additional or new taxes are imposed on Eversource or existing taxes are removed, the Formula Rate will be appropriately modified and filed with the Commission in accordance with Part 35 of the Commission's regulations.

II. In addition to the applicable charges of this Local Service Schedule, and as otherwise specified in the Service Agreement, the Transmission Customer shall pay Eversource Service each month the following additional charges for Non-firm Point-To-Point Transmission Service provided during such month.

A. Taxes and Fees Charge

B. Regulatory Expenses Charge

C. Other

A. **TAXES AND FEES CHARGE**

If any governmental authority requires the payment of any fee or assessment or imposes any form of tax with respect to payments made for Non-Firm Point-To-Point Transmission Service provided under this Local Service Schedule, not specifically provided for in any of the charge or rate provisions under this Local Service Schedule, including any applicable interest charged on any deficiency assessment made by the taxing authority, together with any further tax on such payments, the obligation to make payment for such fee, assessment, or tax shall be borne by the Transmission Customer. Eversource will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's regulations.

B. **REGULATORY EXPENSES**

Eversource reserves its rights to make a Section 205 filing for recovery of its costs to administer this Local Service Schedule and the Service Agreements.

C. **OTHER**

Eversource shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Schedule ES-3 in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE ES-3

Appendix A

CATEGORY A RATE

FOR NON-FIRM POINT-TO-POINT SERVICE

Eversource's Category A Formula Rate for Non-Firm Point-To-Point Transmission Service ("Formula Rate") is an annual rate determined from the following formula.

$$\text{Formula Rate}_i = (A_i - B_i + C_i - D_i) / E_i$$

WHERE:

- i equals the Service Year.

- A is the annual Total Transmission Revenue Requirements (expressed in dollars) as described in Attachment ES-H.

- B is the revenues received (expressed in dollars) from the provision of transmission and other related services to others as recorded in FERC Accounts 456.1 and 454 to the extent that such transactions are not included in the determination of load (E),[2] minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

- C is the transmission payments (expressed in dollars) to the New England System Operator as recorded in FERC Account 565 in accordance with the Tariff.

- D is the sum of the annual revenues received (expressed in dollars) for the costs associated with the Localized Facilities, minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

- E is the average Eversource Monthly Transmission System Category A Load (expressed in kilowatts).

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[2] Includes amortization of revenues from point-to-point transmission service provided to Consolidated Edison Energy Massachusetts, Inc. and NRG Energy, Inc. under contracts in which customers paid based on single lump sum payment.

SCHEDULE ES-3[RESERVED]

SCHEDULE ES-4
CHARGE PROVISIONS FOR LOCAL NETWORK SERVICE

I. Network Customers will pay the following demand charges for Local Network Service.

A. **DEMAND CHARGE A**

1. Determination of Demand Charge:
The Demand Charge will be determined in accordance with Section ~~16.3~~16.4 of this Local Service Schedule.

2. Eversource's Annual Transmission Revenue Requirements:
The annual Transmission Revenue Requirements shall be determined in accordance with the formula specified in Appendix A of this Schedule ES-4 ("Formula Requirements").

B. **DEMAND CHARGE B**

1. Determination of Demand Charge
The Demand Charge will be determined in accordance with Section ~~16.3~~16.4 of this Local Service Schedule.

2. Eversource Annual Transmission Revenue Requirements:
The annual Transmission Revenue Requirements for each Localized Facility of a Designated State or Area shall be determined in accordance with the formula specified in Appendix B of this Schedule ES-4 ("Formula Requirements").

C. TAX RATES AND TAXES

The Formula Requirements set forth in this Schedule ES-4 in effect during a Service Year shall be based on local, state, and federal tax rates and taxes in effect during the Service Year. If, at any time, additional or new taxes are imposed on Eversource or existing taxes are removed, the Formula Requirements will be appropriately modified and filed with the Commission in accordance with Part 35 of the Commission's regulations.

II. In addition to the applicable charges of this Local Service Schedule, and as otherwise specified in the Service Agreement, the Transmission Customer shall pay to Eversource Service each month the following additional charges for Local Network Service provided during such month.

A. Taxes and Fees Charge

B. Regulatory Expenses Charge

C. Other

A. **TAXES AND FEES CHARGE**

If any governmental authority requires the payment of any fee or assessment or imposes any form of tax with respect to payments made for service provided under this Local Service Schedule, not specifically provided for in any of the charge or rate provisions under this Local Service Schedule, including any applicable interest charged on any deficiency assessment by the taxing authority, together with any further tax on such payments, the obligation to make payment for any such fee, assessment, or tax shall be borne by the Transmission Customer. Eversource will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's regulations.

B. **REGULATORY EXPENSES CHARGE**

Eversource shall have the right to make a Section 205 filing for recovery of regulatory expenses associated with this Local Service Schedule and the Service Agreements.

C. **OTHER**

Eversource shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Schedule ES-4 in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE ES-4

Appendix A

NETWORK FORMULA REQUIREMENTS

FOR CATEGORY A COSTS

Eversource's formula requirements for Local Network Service is determined from the following formula.

$$\text{Formula Requirements}_i = A_i – B_i + C_i - D_i$$

WHERE:

- $_i$ equals the Service Year.
- A is the annual Total Transmission Revenue Requirements (expressed in dollars) as described in Attachment ES-H.
- B is the revenues received (expressed in dollars) from the provision of transmission and other related services to others as recorded in FERC Accounts 456.1 and 454 to the extent that such transactions are not included in the determination of load,[2] minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.
- C is the transmission payments to (expressed in dollars) the New England System Operator as recorded in FERC Accounts 565 in accordance with the Tariff.
- D is the sum of the annual revenues received (expressed in dollars) for the costs associated with Localized Facilities, minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

[2] Includes amortization of revenues from point-to-point transmission service provided to Consolidated Edison Energy Massachusetts, Inc. and NRG Energy, Inc. under contracts in which customers paid based on single lump sum payment.

SCHEDULE ES-4

Appendix B

NETWORK FORMULA REQUIREMENTS

FOR CATEGORY B COSTS

Eversource's formula requirements for Local Network Service and for Eligible Customers taking Regional Network Service under this Tariff in a Designated State or Area of a Localized Facility, is determined from the following formula, and separately determined for each Designated State or Area of a Localized Facility.

$$\text{Formula Requirements}_i = D_i$$

WHERE:

- $_i$ equals the Service Year.

- D is the annual Localized Transmission Revenue Requirements (expressed in dollars) of the Localized Facilities of Eversource for a Designated State or Area of a Localized Facility, as described in Attachment ES-I.

ATTACHMENT ES-C

AVAILABLE TRANSFER CAPABILITY METHODOLOGY

TABLE OF CONTENTS

1. Introduction

ISO is the regional transmission organization ("RTO"), serving the New England Control Area. ISO is responsible for the development, oversight, and fair administration of New England's wholesale market, management of the bulk electric power system and wholesale markets' planning processes. The ISO serves as the Balancing Authority for the New England Control Area. The New England Control Area is interconnected to three neighboring Balancing Authority Areas ("BAA"): New Brunswick System Operator Area ("NBSO Area"), New York Independent System Operator Area ("NYISO Area"), and Hydro-Quebec TransEnergie Area ("HQTE Area").

As part of its RTO responsibilities, the ISO is registered with the North American Electric Reliability Corporation ("NERC") as several functional model entities that have responsibilities related to the calculation of ATC as defined in the following NERC Standards: MOD-001 – Available Transmission System Capability ("MOD-001"), MOD-004 – Capacity Benefit Margin ("MOD-004"), and MOD-008 – Transmission Reliability Margin Calculation Methodology ("MOD-008"). The extent of those responsibilities is based on various Commission approved transmission operating agreements and the provisions of the ISO New England Operating Documents.

While the ISO is the Transmission Service Provider for Regional Network Service ("Regional Transmission Service") associated with Pool Transmission Facilities, the Participating Transmission Owners ("PTOs") provide local transmission service over Non-Pool Transmission Facilities within the RTO footprint and are responsible for calculating TTC and ATC associated with Local Transmission Service provided under Schedule 21 pursuant to the Transmission Operating Agreement ("TOA"). Pursuant to CFR § 37.6(b)[1] of the FERC Regulations Transmission Provider's are obligated to calculate and post TTC and ATC for each Posted Path. The ISO is not responsible for the calculation of these values.

Pursuant to the terms of the Transmission Operating Agreement executed between the companies comprising Eversource hereunder as Participating Transmission Owners ("PTOs") and ISO, Eversource is a Transmission Service Provider and calculates TTC and ATC for certain Local Facilities over which Point-to-Point transmission service is provided under Schedule 21-ES of the ISO Open Access Transmission Tariff ("ISO OATT").

[1] §37.6(b) Posting transfer capability. The available transfer capability on the Transmission Provider's system (ATC) and the total transfer capability (TTC) of that system shall be calculated and posted for each Posted Path as set out in this section.

Posted Path is defined as any control area to control area interconnection; any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a customer requests to have ATC or TTC posted. For this last category, the posting must continue for 180 days and thereafter until 180 days have elapsed from the most recent request for service over the requested path. For purposes of this definition, an hour includes any part of any hour during which service was denied, curtailed or interrupted (§37.6(b)(1)(i)).

Non-PTF facilities are primarily radial paths that provide transmission service directly to interconnected generators. It is possible, in the future that a particular path may interconnect more nameplate capacity generation than the path's TTC. However, for Eversource's Non-PTF modeled by the ISO or the Local Control Center ("LCC"), the ISO or the LCC will only dispatch an amount of generation interconnected to such path so as not to incur a reliability or stability violation on the subject path consistent with ISO's economic, security constrained dispatch methodology.

Eversource does not currently have any Posted Paths based on the above definition. However, if Eversource does have any Posted Path(s) in the future, Eversource will calculate TTC using NERC Standard MOD-029-1 Rated System Path Methodology as outlined below.

1.1 Scope of Document

The scope of this document is limited to those functions performed or utilized by Eversource as the Transmission Provider of Schedule 21-ES Local Point-to Point transmission service over Non-PTF pursuant to the PTOs' Transmission Operating Agreement and the ISO OATT:

- Total Transfer Capability (TTC) methodology
- Available Transfer Capability (ATC) methodology
- Existing Transmission Commitment (ETC)
- Use of Rollover Rights (ROR) in the calculation of ETC

As explained in Section 2, TTC and ATC are required to be calculated only for certain non-PTF internal Posted Paths over which Local Point-to-Point transmission service is provided under Schedule 21-ES. TTC and ATC is not calculated by Eversource for Local Network Service because ISO employs a market model for economic, security constrained dispatch of generation, and Eversource does not require advance reservation for such network service.

2. Transmission Service in the New England Markets

Since the inception of the OATT for New England, the process by which generation located inside New England supplies energy to the bulk electric system has differed from the Commission's pro forma OATT. The fundamental difference is that internal generation is dispatched in an economic, security constrained manner by the ISO rather than utilizing a system of physical rights, advance reservations and point-to-point transmission service. Through this process, internal generation provides offers that are utilized by the ISO in the Real-Time Energy Market dispatch software. This process provides the least-cost dispatch to satisfy Real-Time load on the system.

In addition to offers from generation within New England, entities may submit External Transactions to move energy into the ISO Area, the New England Control Area, out of the New England Control Area, or through the New England Control Area. The Real-Time Energy Market clears these External Transactions based on forecast Locational Marginal Pricing (LMPs) and the transfer capability of the associated external interfaces. With those External Transactions in place, the Real-Time Energy Market dispatches internal generation in an economic, security constrained manner to meet Real-Time load within the region.

This process for submitting External Transactions into the New England Real-Time Energy Market does not require an advance physical reservation for use of the PTF. In the event that the net of the economic External Transactions is greater than the transfer capability of the associated external interface, the External Transactions selected to flow are selected based on the rules specified in the Tariff. For any External Transactions that are confirmed to flow in Real-Time based on the economics of the system, a transmission reservation for RNS and Through or Out Service is created after-the-fact to satisfy the transparency needs of the market.

The process described above is applicable to the PTF within the ISO Area, and non-PTF Local Facilities where utilized for Local Network Service by generation or load. However, Eversource owns Local Facilities over which an advance transmission service reservation for firm or non-firm transmission service may be required. On those Local Facilities, the market participant may obtain a transmission service reservation from Eversource under Schedule 21-ES prior to delivery of energy into the New England Wholesale Market. This document addresses the calculation of ATC and TTC for these non-PTF internal paths.

3. Eversource **Total Transfer Capability (TTC)**

The Total Transfer Capability (TTC) is the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions. TTC for Schedule 21-ES is calculated using NERC Standard MOD-029-1 Rated System Path Methodology and posted on Eversource's OASIS site.

Eversource will calculate and post TTC on its OASIS site for all non-PTF Posted Paths that are eligible for Point-to-Point transmission service reservations. The TTC on Eversource's non-PTF Local Facilities that are eligible for Local Point-to-Point transmission service reservations are relatively static values. Eversource thus calculate the TTC for Non-PTF Posted Paths that may require Local Point-to-Point Local Point-to-Point transmission reservations on its OASIS provider page according to NAESB Standards.

4. Capacity Benefit Market (CBM)

CBM is defined as the amount of firm transmission transfer capability set aside by a TSP for use by the Load Serving Entities. The ISO does not set aside any CBM for use by the Load Serving Entities, because of the New England approach to capacity planning requirements in the ISO New England Operating Documents. Load Serving Entities operating within the New England Control Area are required to arrange for their Capacity Requirements prior to the beginning of any given month in accordance with ISO Tariff, Section III.13.7.3.1 (Calculation of Capacity Requirement and Capacity Load Obligation). Load Serving Entities do not utilize CBM to ensure that their capacity needs are met; therefore, CBM is not applicable within the New England market design. Accordingly, for purposes of Eversource's ATC calculation and because CBM for the New England Control Area is set to zero (0), Eversource utilizes a zero (0) CBM value.

Existing Transmission Commitments, Firm (ETC_F)

The ETC_F are those confirmed Firm transmission reservations (PTP_F) plus any rollover rights for Firm transmission reservations (ROR_F) that have been exercised. There are no allowances necessary for Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$),

grandfathered Transmission Service (GF_F) and other service(s), contract(s) or agreement(s) (OS_F) to be considered in the ETC_F calculation.

Existing Transmission Commitments, Non-Firm(ETC_{NF})

The (ETC_{NF}) are those confirmed Non-Firm transmission reservations (PTP_{NF}). There are no allowances necessary for Non-Firm Network Integration Transmission Service ($NITS_{NF}$), Non-Firm grandfathered Transmission Service (GF_{NF}) or other service(s), contract(s) or agreement(s) (OS_{NF}).

5. Transmission Reliability Margin (TRM)

TRM is the amount of transmission transfer capability set aside to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. It is used only for external interfaces under the New England market design. Eversource does not have any external interfaces, and therefore TRM for Eversource's non-PTF facilities is zero.

6. Calculation of ATC for Eversource's Local Facilities - General Description:

NERC Standards MOD-001-1 – Available Transmission System Capability and MOD-029-1 – Rated System Path Methodology define the required items to be identified when describing a transmission provider's ATC methodology. As a practical matter, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

Common practice is not to calculate or post firm and non-firm ATC values for the non-PTF assets described above, as ATC is positive and listed as 9999. Transmission customers are not restricted from reserving firm or non-firm transmission service on non-PTF facilities.

As Real-Time approaches, the ISO utilizes the Real-Time energy market rules to determine which of the submitted energy transactions will be scheduled in the coming hour. Basically, the ATC of the non-PTF assets in the New England market is almost always positive. With this simplified version of ATC, there is no detailed algorithm to be described or posted. Thus, for those non-PTF facilities that serve as a path for Eversource's Schedule 21-ES Point-to-Point Transmission Customers, Eversource has posted the ATC as 9999, consistent with industry practice. ATC on these paths varies depending on the time of day.

However, it is posted with an ATC of "9999" to reflect the fact that there are no restrictions on these paths for commercial transactions.

6.1 Calculation of Schedule 21-ES Firm ATC (ATC_F)

6.1.1 Calculation of ATC_F in the Planning Horizon (PH)

For purposes of this Attachment C PH is any period before the Operating Horizon.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for TRM, CBM, ETC_F, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM are zero. Firm Transmission Service under Schedule 21-ES that is available in the Planning Horizon (PH) includes: Yearly, Monthly, Weekly, and Daily. $Postbacks_F$ and $counterflows_F$ of Schedule 21-ES transmission reservations are not considered in the ATC calculation. Therefore, ATC_F in the PH is equal to the TTC minus ETC_F

6.1.2 Calculation of ATC_F in the Schedule 21-ES Operating Horizon (OH)

For purposes of this Attachment C OH is noon eastern prevailing time each day. At that time, the OH spans from noon through midnight of the next day for a total of 36 hours. As time progresses, the total hours remaining in the OH decreases until noon the following day when the OH is once again reset to 36 hours.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for ETC_F, CBM, TRM, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM is zero. Daily Firm Transmission Service under Schedule 21-ES is the only firm service offered in the Operating Horizon (OH). $Postbacks_F$ and $counterflows_F$ of Schedule 21-ES transmission reservations are not considered in the ATC_F calculation. Therefore, ATC_F in the OH is equal to the TTC minus ETC_F.

6.1.3 Because Firm Schedule 21-ES transmission service is not offered in the Scheduling Horizon (SH): ATC_F in the SH is zero.

6.2 Calculation of Schedule 21-ES Non-Firm ATC (ATC_{NF})

6.2.1 Calculation of ATC_{NF} in the PH

ATC_{NF} is the capability for Non-Firm transmission reservations that remain after allowing for ETC_{F}, ETC_{NF}, scheduled CBM (CBM_{S}), unreleased TRM (TRM_{U}), Non-Firm Postbacks ($Postbacks_{NF}$) and Non-Firm counterflows ($counterflows_{NF}$).

As discussed above, the TRM and CBM for Schedule 21-ES are zero. Non-Firm ATC available in the PH includes: Monthly, Weekly, Daily and Hourly. TRM_{U}, $Postbacks_{NF}$ and $counterflows_{NF}$ of Schedule 21-ES transmission reservations are not considered in this calculation. Therefore, ATC_{NF} in the PH is equal to the TTC minus ETC_{F} and ETC_{NF} .

6.2.2 Calculation of ATC_{NF} in the OH

ATC_{NF} available in the OH includes: Daily and Hourly.

As discussed above TRM and CBM for Schedule 21-ES are zero. TRM_{U}, counterflows and ETC_{NF} are not considered in this calculation. Therefore, ATC_{NF} in the OH is equal to the TTC minus $ETC_{F,}$ plus postbacks of PTP_{F} in OH as PTP_{NF} ($Postbacks_{NF}$)

6.3 Negative ATC

As stated above, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

As stated above, Eversource's non-PTF facilities are primarily radial paths that provide transmission service to directly interconnected generators. It is possible, in the future, that a particular radial path may interconnect more nameplate capacity generation than the path's TTC. However, due to the ISO's security constrained dispatch methodology, the ISO will only dispatch an amount of generation interconnected to such path so as not to incur a reliability or stability violation on the subject path. Therefore, ATC in the PH, OH and SH may become zero, but will not become negative.

7. Posting of Schedule 21-ES ATC

7.1 Location of ATC Posting

ATC values are posted on Eversource's OASIS site.

7.2 Updates To ATC

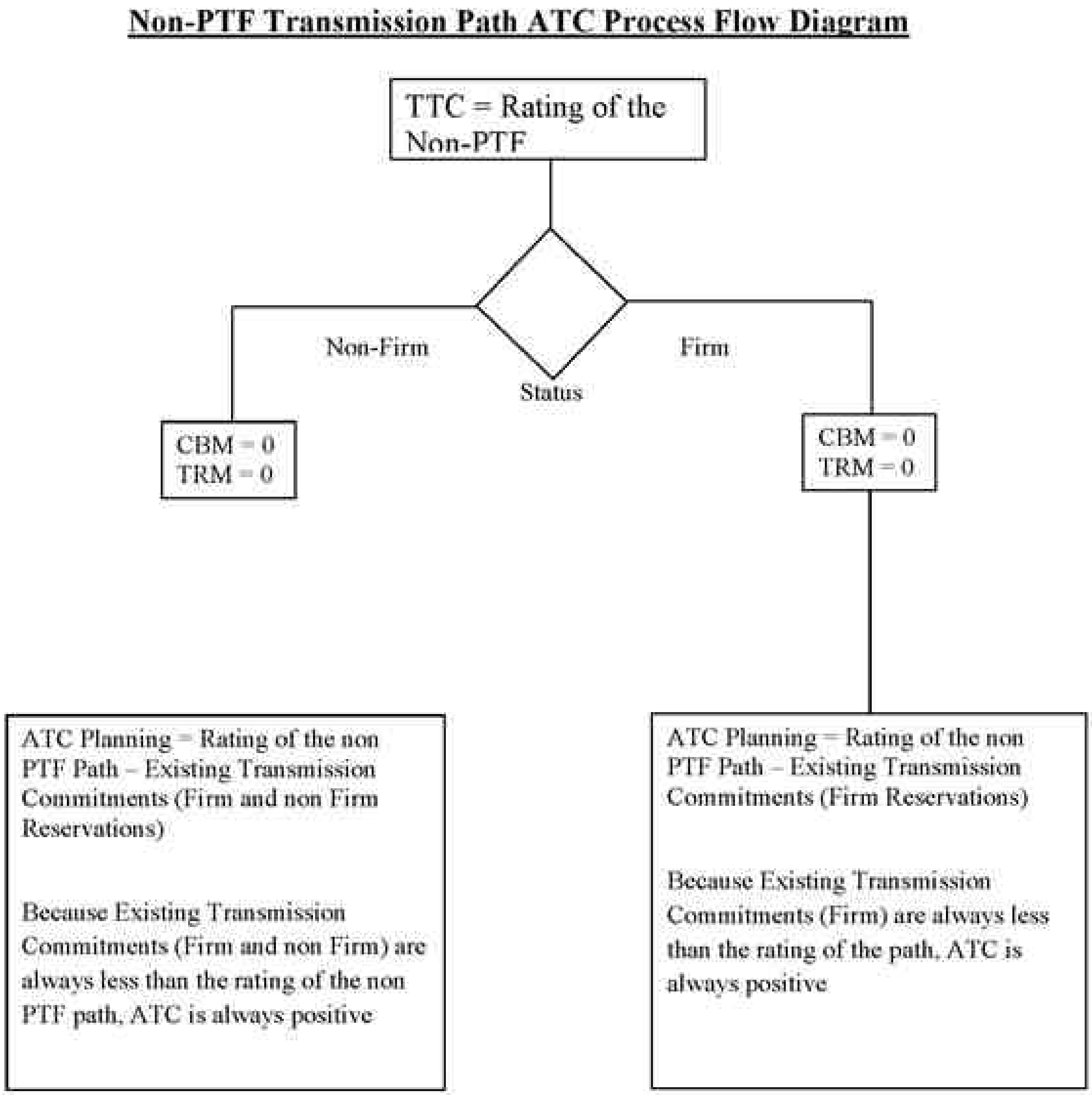
When any of the variables in the ATC equations change, the ATC values are recalculated and immediately posted.

7.3 Coordination of ATC Calculations

Schedule 21-ES non-PTF has no external interfaces. Therefore it is not necessary to coordinate the values.

7.4 Mathematical Algorithms A link to the actual mathematical algorithm for the calculation of ATC for the Eversource non-PTF internal interfaces is located at https://www.eversource.com/Content/docs/default-source/Tranmission/attachment-6.pdf?sfvrsn=0.

8. Process Flow Diagram for ATC Calculation



ATTACHMENT ES-D
PENALTY DISBURSEMENT METHODOLOGY

Late Study Penalties: Penalties paid by the Transmission Provider pursuant to Schedule 21 are referred to as "Late Study Penalties," and therefore subject to distribution to all Transmission Customers that are not affiliated with the Transmission Provider. On the month following the end of each calendar quarter, each Transmission Customer that is not affiliated with the Transmission Provider shall receive, on the relevant monthly invoice, a credit for its share of the Late Study Penalties that were assessed during the applicable calendar quarter. The Transmission Customer's share of the Late Study Penalties (if any) will be determined as follows:

(a) For each quarter, the Transmission Provider will determine: (1) the sum of all Late Study Penalties assessed during the quarter measured in dollars (LSRq), and (2) the sum of all transmission revenue from Transmission Customers that are not affiliated with the Transmission Provider during that quarter, measured in dollars (LSTRq). Where:

LSRq = Late Study Penalty Revenue in the quarter
LSTRq = Transmission Revenue from Transmission Customers not affiliated with the Transmission Provider in the quarter

(b) For each quarter, each Transmission Customer that was not affiliated with the Transmission Provider will receive a credit equal to the product of (i) LSRq multiplied by (ii) a fraction derived from dividing the amount of transmission revenue from that Transmission Customer (TC1) during that quarter (measured in dollars), where TC1 is equal to one Transmission Customer, and a denominator equal to LSTRq.

(c) The Transmission Provider shall apply the credit for Late Study Penalties to service that the non-affiliated Transmission Customer takes from the Transmission Provider pursuant to this Schedule 21-ES. Any remaining credit will be refunded to the Transmission Customer.

ATTACHMENT ES-E

LOCALIZED COSTS RESPONSIBILITY **AGREEMENT**

This Localized Costs Responsibility Agreement ("LCRA" or "Agreement"), dated as of _______________________, is entered into by and between the Eversource Energy Service Company ("Eversource Service" or "COMPANY"), acting as agent for [The Connecticut Light and Power Company, Western Massachusetts Electric Company, Public Service Company of New Hampshire], andthe "Transmission Customer".

The Transmission Customer is _____________________________________. The Transmission Customer has been determined to be an Eligible Customer taking Regional Network Service under the Tariff whose load **is located in the** Designated State or Area for a **Localized** Facility listed in **Section** 16.3 **of** Schedule 21-ES of the Tariff**.**

The Transmission Customer agrees to pay its portion of the cost of Localized Facilities in the Designated State or Area in which the Transmission Customer's load is located as provided in the Tariff and in accordance with Commission orders. Billing under this Agreement shall commence on the later of: (1) 0001 hours on _____________________, or (2) such other date as permitted by the Commission.

Charges under this Agreement shall terminate on the earlier of: (1) the date on which the costs of the Localized Facilities in the Designated State or Area in which the Transmission Customer's load is located are fully depreciated; or (2) the date upon which the Transmission Customer no longer takes Regional Network Service under the Tariff in the Designated State or Area in which the Transmission Customer's load is located; provided, that the Transmission Customer shall remain responsible for all final payment obligations. In the event that the Transmission Customer sells or assigns, or transfers its load to another entity ("New Transmission Customer"), the Transmission Customer must provide Eversource Service with at least ninety (90) calendar days advance written notice of the sale, assignment, or transfer.

The Transmission Customer shall remain liable for the performance of all obligations under this Agreement until a new LCRA has been executed between the New Transmission Customer and Eversource Service, or in the case of an unexecuted LCRA, such other date as it has been **permitted to** be made effective by the Commission. No sale or assignment shall **become effective** until the Parties have complied with all Applicable Laws and Regulations required for such sale, assignment, or transfer**.**

Other special provisions (if any)
____.

Any notice or request made to or by any Party regarding this greement shall be made in writing and shall be telecommunicated or delivered either in person, or by prepaid mail (return receipt requested) to the representative of the other Party as indicated below. Such representative and address for notices or requests may be changed from time to time by notice by one Party to the other.

COMPANY:

____

____

____

TRANSMISSION CUSTOMER:

____

____

____

Any exhibits to thisAgreement and the Tariff are incorporated herein and made a part hereof. ThisAgreement may be amended, from time to time, as provided for in Schedule 21-ES of the Tariff.

IN WITNESS WHEREOF, the Parties have caused thisAgreement to be executed by their respective authorized officials as of the date first above written.

EVERSOURCE ENERGY SERVICE COMPANY
By: ____________________________________
Its ________________________

TRANSMISSION CUSTOMER
By: __________________________________
Its ____________________________________

ATTACHMENT ES-G
NETWORK OPERATING AGREEMENT

This Network Operating Agreement is an appendix to Schedule 21-ES (this Local Service Schedule) of the OATT and operates as an implementing agreement for Local Network Service under this Local Service Schedule. This Network Operating Agreement is subject to and in accordance with Part III of this Local Service Schedule. All definitions and other terms and conditions of this Local Service Schedule are incorporated herein by reference.

1.0 Definitions:

1.1 Data Acquisition Equipment

Supervisory control and data acquisition ("SCADA"), remote terminal units ("RTUs") to obtain information from a Party's facilities, telephone equipment, leased telephone circuits, fiber optic circuits, and other communications equipment necessary to transmit data to remote locations, and any other equipment or service necessary to provide for the telemetry and control requirements of this Local Service Schedule.

1.2 Data Link

The direct communications link between the Transmission Customer's energy control center and Eversource’s designated location(s) that will enable Eversource to receive real time telemetry and data from the Transmission Customer.

1.3 Metering Equipment

High accuracy, solid state kW, kVAR, kWh meters, metering cabinets, metering panels, conduits, cabling, high accuracy current transformers and high accuracy potential transformers, which directly or indirectly provide input to meters or transducers, metering recording devices, telephone circuits, signal or pulse dividers, transducers, pulse accumulators, metering sockets, test switch devices, enclosures, conduits, and any other metering, telemetering or communication equipment necessary to implement the provisions of this Local Service Schedule.

1.4 Protective Equipment

Protective relays, relaying panels, relaying cabinets, circuit breakers, conduits, cabling, current transformers, potential transformers, coupling capacitor voltage transformers, wave traps, transfer trip and

fault recorders, which directly or indirectly provide input to relays, fiber optic communication equipment, power line carrier equipment and telephone circuits, and any other protective equipment necessary to implement the protection provision of this Local Service Schedule.

2.0 Term

The term shall be as provided in the Service Agreement consistent with this Local Service Schedule (including, but not limited to, application procedures, commencement of service, and effect of termination).

3.0 Point(s) Of Interconnection

Local Network Service will be provided by Eversource at the point(s) of interconnection specified in Appendix __, as amended from time to time. Each point of interconnection in this listing shall have a unique identifier, meter location, meter number, metered voltage, terms on meter compensation and designation of current or future year of in service.

4.0 Cogeneration And Small Power Production Facilities

If a Qualifying Facility is located or locates in the future on the System of the Transmission Customer, and the owner or operator of such Qualifying Facility sells the output of such Qualifying Facility to an entity other than the Transmission Customer, the delivery of such Qualifying Facility's power shall be subject to and contingent upon transmission arrangements being established with Eversource prior to commencement of delivery of any such power and energy.

5.0 Character Of Service

Network Transmission Service at the points of interconnection shall be in the form of single phase or balanced three-phase alternating current at a frequency of sixty (60) hertz. The Transmission Customer shall operate and maintain its electric system in a manner that avoids: (i) the generation of harmonic frequencies exceeding the limits established by the latest revision of IEEE-519; (ii) voltage flicker exceeding the limits established by the latest revision of IEEE-141; (iii) negative sequence currents; (iv) voltage or current fluctuations; (v) frequency variations; or (vi) voltage or power factor levels that could adversely affect Eversource’s electrical equipment or facilities or those of its customers, and in a manner that complies with all applicable NERC, NPCC, ISO and Eversource’s operating criteria, rules, regulations, procedures, guidelines and interconnection standards as amended from time to time.

6.0 Continuity Of Service

(a) Eversource and the Transmission Customer shall operate and maintain their respective network systems, in accordance with Good Utility Practice, and in a manner that will allow Eversource to safely and reliably operate the Eversource Transmission System in accordance with this Local Service Schedule, so that either Party shall not unduly burden the other Party; provided, however, that notwithstanding any other provision of this Local Service Schedule, Eversource shall retain the sole responsibility and authority for all operating decisions that could affect the integrity, reliability and security of the Eversource Transmission System.

(b) Eversource shall exercise reasonable care and Due Diligence to ensure Local Network Service hereunder in accordance with Good Utility Practice; provided, however, that Eversource shall not be responsible for any failure to ensure electric power service, nor for interruption, reversal or abnormal voltage of the service, if such failure, interruption, reversal or abnormal voltage is due to a Force Majeure.

7.0 Power Factor

(a) Where Local Network Service provided under this Local Service Schedule is for delivery of power to a load center of the Transmission Customer served from the Eversource Transmission System, the Transmission Customer shall maintain load power factor levels, during both on- and off- peak hours, appropriate to meet the operating requirements of Eversource, and shall follow the ISO standards and practices, as set forth in the Service Agreement.

(b) Where Local Network Service provided under this Local Service Schedule is for delivery of power from a generating facility connected to the Eversource Transmission System, the Transmission Customer shall deliver power at a lagging or leading power factor as set forth in the Service Agreement.

(c) Where Local Network Service provided under this Local Service Schedule is for delivery of power from outside the Eversource Transmission System, the obligation to maintain proper sending and receiving end voltages rests with the Transmission Customer, as set forth in the Service Agreement.

(d) In the event that the power factor levels and reactive supply requirements set forth in the Service Agreement are not maintained by the Transmission Customer, Eversource shall thereupon have the right to take the appropriate corrective action and to charge the Transmission Customer for the costs thereof.

Eversource shall have the right, at any time, unilaterally to make a Section 205 filing with the Commission for the recovery of any such costs.

8.0 Metering

(a) The Transmission Customer shall, at its expense, purchase all necessary metering equipment to accurately account for the electric power being transmitted under this Local Service Schedule. Eversource may require the installation of telemetering equipment for the purposes of billing, power factor measurements and to allow Eversource to maximize economic and reliable operation of its transmission system. Such metering equipment shall meet the specifications and accepted metering practices of Eversource and applicable criteria, rules, standards and operating procedures, or such successor rules and standards. At Eversource's option, communication metering equipment may be installed in order to transmit meter readings to Eversource's designated locations.

(b) Electric power being transmitted under this Local Service Schedule will be measured by meters at all points of interconnection and/or on generating facilities (Network and non-Network Resources) located on and outside the Transmission Customer's system as required by Eversource.

(c) The Transmission Customer shall purchase meters capable of time-differentiated (by hour) measurement of the instantaneous flow in kW and net active power flow in kWh and of reactive power flow. All meters shall compensate for applicable line and/or transformer losses in accordance with Good Utility Practice when measurement is made at any location other than the point of interconnection.

(d) Eversource reserves the right: (i) to determine metering equipment ownership; (ii) to determine the equipment installation at each point of interconnection; (iii) to require the Transmission Customer to install the equipment -- or -- install the equipment with the Transmission Customer supplying without cost to Eversource a suitable place for the installation of such equipment; (iv) to determine other equipment allowed in the metering circuit; (v) to determine metering accuracy requirements; (vi) to determine the responsibilities for operation, maintenance, testing and repair of metering equipment.

(e) Eversource shall have access to metering data, including telephone line access, which may reasonably be required to facilitate measurement and billing under this Local Service Schedule. Eversource may require the Transmission Customer provide, at its expense, a separate dedicated voice grade telephone circuit for Eversource and the Transmission Customer to remotely access each meter.

Metering equipment and data shall be accessible at all reasonable hours for purposes of inspection and reading.

(f) All metering equipment shall be tested in accordance with practices of Eversource, applicable criteria, rules, standards and operating procedures or upon the request by Eversource. If at any time metering equipment fails to register or is determined to be inaccurate, in accordance with Eversource's practices and applicable criteria, rules, standards and operating procedures, the Transmission Customer shall make the equipment accurate as soon thereafter as practicable, and the meter readings and rate computation for the period of such inaccuracy, insofar as can reasonably be ascertained, shall be adjusted; provided, however, that no adjustment to charges shall be required for any period exceeding two (2) months prior to the date of the test. Representatives of Eversource will be afforded opportunity to witness such tests.

9.0 Network Load

The Transmission Customer shall provide Eversource with the actual hourly Network Load for each calendar month by the seventh day of the following calendar month.

10.0 Data Transfer:

(a) The Transmission Customer shall provide timely, accurate real time information to Eversource in order to facilitate performance of its obligations under this Local Service Schedule.

(b) The selection of real time telemetry and data to be received by Eversource and the Transmission Customer shall be necessary for safety, reliability, security, economics, and/or monitoring of real-time conditions that affect the Eversource Transmission System. This telemetry shall include, but is not limited to, loads, line flows (MW and MVAR), voltages, generator output, and status of substation equipment at any of the Transmission Customer's transmission and generation facilities. To the extent that Eversource or the Transmission Customer requires data that are not available from existing equipment, the Transmission Customer shall, at its expense and at locations designated by Eversource or the Transmission Customer, install any metering equipment, data acquisition equipment, or other equipment and software necessary for the telemetry to be received by Eversource or the Transmission Customer. Eversource shall have the right to inspect equipment and software associated with the data transfer in order to assure conformance with Good Utility Practices.

11.0 Maintenance of Equipment

The Transmission Customer shall, on a regular basis in accordance with practices of Eversource, applicable criteria, rules, standards and operating procedures or at the request of Eversource, and at its expense, test, calibrate, verify and validate the data link, metering equipment, data acquisition equipment, transmission equipment, protective equipment and other equipment or software used to implement the provisions of this Local Service Schedule. Eversource shall have the right to inspect such tests, calibrations, verifications and validations of the data link, metering equipment, data acquisition equipment, transmission equipment, protective equipment and other equipment or software used to implement the provisions of this Local Service Schedule. Upon Eversource's request, the Transmission Customer will provide Eversource a copy of the installation, test and calibration records of the data link, metering equipment, data acquisition equipment, transmission equipment, protective equipment and other equipment or software. Eversource shall, at the Transmission Customer's expense, have the right to monitor the factory acceptance test, the field acceptance test, and the installation of any metering equipment, data acquisition equipment, transmission equipment, protective equipment and other equipment or software used to implement the provisions of this Local Service Schedule.

12.0 Notification

(a) The Transmission Customer shall notify and coordinate with Eversource prior to the commencement of any work or maintenance by the Transmission Customer, Network Member, or contractors or agents performing on behalf of either or both, which may directly or indirectly have an adverse effect on the Transmission Customer or Eversource's data link, or the reliability of the Eversource Transmission System. All notifications for scheduled outages of the data link, metering equipment, data acquisition equipment, transmission equipment, protective equipment and other equipment or software must meet the requirements of the ISO and Eversource.

13.0 Emergency System Operations

(a) The Transmission Customer, at its expense, shall be subject to all applicable emergency operation standards promulgated by NERC, NPCC, ISO and Eversource which may include but not limited to underfrequency relaying equipment, load shedding equipment and voltage reduction equipment.

(b) Eversource reserves the right to take whatever actions they deem necessary to preserve the integrity of the Eversource Transmission System during emergency operating conditions. If the Local Network Service at the points of interconnection is causing harmful physical effects to the Eversource

Transmission System facilities or to its customers (e.g., harmonics, undervoltage, overvoltage, flicker, voltage variations, etc.), Eversource shall promptly notify the Transmission Customer and if the Transmission Customer does not take the appropriate corrective actions immediately, Eversource shall have the right to interrupt Local Network Service under this Local Service Schedule in order to alleviate the situation and to suspend all or any portion of Local Network Service under this Local Service Schedule until appropriate corrective action is taken.

(c) In the event of any adverse condition or disturbance on the Eversource Transmission System or on any other system directly or indirectly interconnected with the Eversource Transmission System, Eversource may, as it deems necessary, take actions or inactions that, in Eversource's sole judgment, result in the automatic or manual interruption of Local Network Service in order to: (i) limit the extent or damage of the adverse condition or disturbance; (ii) prevent damage to generating or transmission facilities; (iii) expedite restoration of service; or (iv) preserve public safety.

14.0 Cost Responsibility

(a) The Transmission Customer shall be responsible for the costs incurred by the Transmission Customer and Eversource to implement the provisions of this Local Service Schedule including, but not limited to, engineering, administrative and general expenses, material and labor expenses associated with the specifications, design, review, approval, purchase, installation, maintenance, modification, repair, operation, replacement, checkouts, testing, upgrading, calibration, removal, and relocation of equipment, or software.

(b) Additionally, the Transmission Customer shall be responsible for all costs incurred by the Transmission Customer and Eversource for on-going operation and maintenance of the metering, telecommunications and safety protection facilities and equipment required to implement the provisions of this Local Service Schedule. Such work shall include, but not limited to, normal and extraordinary engineering, administrative and general expenses, material, and labor expenses associated with the specifications, design, review, approval, purchase, installation, maintenance, modification, repair, operation, replacement, checkouts, testing, upgrading, calibration, removal, or relocation of equipment required to accommodate service under this Local Service Schedule.

15.0 Default

The Transmission Customer's failure to implement the terms and conditions of this Network Operating Agreement will be deemed to be a default under this Local Service Schedule and will result in Eversource seeking, consistent with FERC rules and regulations, immediate termination of service under this Local Service Schedule.

16.0 Regulatory Filings

Nothing contained in this Local Service Schedule or any associated Service Agreement, including this Network Operating Agreement, shall be construed as affecting in any way the right of Eversource to unilaterally make application to the Commission for a change in any portion of this Network Operating Agreement under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

IN WITNESS WHEREOF, the Parties have caused this Network Operating Agreement to be executed by their respective authorized officials as of the date written.

Date: __________________________

<u>Eversource Energy Service Company</u>
by: _______________________________
its Vice President

<u>Transmission Customer</u>
by: _______________________________
its _______________________________

ATTACHMENT ES-H
ANNUAL TRANSMISSION REVENUE REQUIREMENTS

Attachment ES-H Methodology:

This formula sets forth the method that Eversource will use to determine its annual Total Transmission Revenue Requirements. The Transmission Revenue Requirements reflect Eversource's total cost to own, operate and maintain the transmission facilities used for providing Open Access Transmission Service to transmission customers under this Local Service Schedule. The Transmission Revenue Requirements will be an annual formula rate calculation, effective for an initial term commencing on the effective date established by FERC and ending on May 31 of the following year. The calculation will be based on the previous calendar year's FERC Form 1 data, with an estimate of Eversource's current year average plant additions, Construction Work in Progress (CWIP), and the Allowance for Funds Used During Construction (AFUDC) regulatory liability account. Plant additions will be multiplied by a fixed charge carrying cost, and CWIP and the AFUDC regulatory liability account will be multiplied by the Cost of Capital. The revenue requirements will be updated thereafter each June 1 based on actual costs from the Service Year. The true-up information will be based on actual data, in lieu of allocated data if specifically identified in the FERC Form 1. For a capital addition whose cost exceeds $20 million, Eversource will make rate base adjustments to estimates and in the true-up process to represent the estimated and actual in-service dates for the capital addition. Specifically, Eversource will adjust for transmission plant, CWIP, AFUDC regulatory liability, accumulated depreciation and accumulated deferred taxes.

I. Definitions

Capitalized terms not otherwise defined in the Tariff and as used in this formula have the following definitions:

A. Allocation Factors

1. <u>Transmission Wages and Salaries Allocation Factor</u> shall equal the ratio of Eversource's Transmission-related direct wages and salaries, including those of affiliated companies, to Eversource's total direct wages and salaries, including those of affiliated companies, excluding administrative and general wages and salaries.

2. Plant Allocation Factor shall equal the ratio of the sum of total investment in Transmission Plant and Transmission Related General Plant to Total Plant in Service.

B. Terms

Administrative and General Expense shall equal Eversource's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928 and 930.1 and excluding Merger-Related Costs included in FERC Account Nos. 920-935 (other than those in FERC Account Nos. 924, 928 and 930.1, which have already been excluded).

AFUDC Regulatory Liability shall equal the unamortized balance of the capitalized AFUDC booked on Eversource's transmission projects as recorded in FERC Account 254 consistent with Commission orders.

Amortization of Loss on Reacquired Debt shall equal Eversource's expenses as recorded in FERC Account No. 428.1.

Amortization of Investment Tax Credits shall equal Eversource's credits as recorded in FERC Account No. 411.4.

Depreciation Expense for Transmission Plant shall equal Eversource's transmission expense as recorded in FERC Account No. 403.

Dispatch Center means CL&P's CONVEX dispatch center.

Dispatch Center Plant shall equal CL&P's gross plant balance for the Dispatch Center as recorded in FERC Account Nos. 350-359 and 389-399.

Dispatch Center Depreciation Expense shall equal the Dispatch Center depreciation expense as recorded in FERC Account No. 403.

Dispatch Center Amortization of Investment Tax Credits shall equal the Dispatch Center amortization of investment tax credits as recorded in FERC Account No. 411.4.

Dispatch Center Accumulated Deferred Income Taxes shall equal the net of Eversource’s Dispatch Center deferred tax balance as recorded in FERC Account Nos. 281-283 and Eversource’s Dispatch Center deferred tax balance as recorded in FERC Account No. 190.

Dispatch Center Municipal Tax Expense shall equal the Dispatch Center municipal tax expense as recorded in FERC Account Nos. 408.1 and 409.1.

General Plant shall equal Eversource’s gross plant balance as recorded in FERC Account Nos. 389-399, less the Dispatch Center general plant.

General Plant Depreciation Expense shall equal Eversource’s general plant expenses as recorded in FERC Account No. 403.

General Plant Depreciation Reserve shall equal Eversource’s general plant reserve balance as recorded in FERC Account No. 108 less the portion of such reserve for the Dispatch Center.

Merger-Related Costs shall equal Eversource’s amortized merger-related costs as authorized by FERC or by state regulatory order.

Other Regulatory Assets/Liabilities – FAS 106 shall equal the net of Eversource’s FAS 106 balance as recorded in FERC Account No. 182.3 and any FAS 106 balance as recorded in Eversource’s FERC Account No. 254.

Other Regulatory Assets/Liabilities – FAS 109 shall equal the net of Eversource’s FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in Eversource’s FERC Account No. 254.

Payroll Taxes shall equal those payroll expenses as recorded in Eversource’s FERC Account Nos. 408.1 and 409.1.

Plant Held for Future Use shall equal Eversource’s balance in FERC Account No. 105.

Prepayments shall equal Eversource’s prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal Eversource’s expenses as recorded in FERC Account No. 924.

Total Accumulated Deferred Income Taxes shall equal the net of Eversource's deferred tax balance as recorded in FERC Account Nos. 281-283 and Eversource's deferred tax balance as recorded in FERC Account No. 190.

Total Loss on Reacquired Debt shall equal Eversource's expenses as recorded in FERC Account 189.

Total Municipal Tax Expense shall equal Eversource's expenses as recorded in FERC Account Nos. 408.1, 409.1.

Total Plant in Service shall equal Eversource's total gross plant balance as recorded in FERC Account Nos. 301-399.

Total Transmission Depreciation Reserve shall equal Eversource's Transmission reserve balance as recorded in FERC Account 108 less the portion of such reserve for the Dispatch Center.

Transmission Merger-Related Costs shall equal Eversource's amortized merger-related transmission costs as authorized by FERC.

Transmission Operation and Maintenance Expense shall equal Eversource's expenses as recorded in FERC Account Nos. 560, 561.5 – 561.8, 562-564 and 566-576.5 and shall exclude all HQ HVDC expenses booked to accounts 560 through 576.5 and expenses already included in Transmission Support Expense, as described in Section I below, that are included in FERC Account Nos. 560-576.5.

Transmission Plant shall equal Eversource's gross plant balance as recorded in FERC Account Nos. 350-359, less Dispatch Center transmission plant.

Transmission Plant Materials and Supplies shall equal Eversource's balance as assigned to transmission, as recorded in FERC Account 154.

Transmission Related Construction Work in Progress shall equal Eversource's investment in Transmission-related projects as recorded in FERC Account 107 consistent with commission orders.

II. Calculation of Transmission Revenue Requirements

The Transmission Revenue Requirement shall equal the sum of Eversource's (A) Return and Associated Income Taxes, (B) Transmission Depreciation Expense, (C) Transmission Related Amortization of Loss on Reacquired Debt, (D) Transmission Related Amortization of Investment Tax Credits, (E) Transmission Related Municipal Tax Expense, (F) Transmission Related Payroll Tax Expense, (G) Transmission Operation and Maintenance Expense, (H) Transmission Related Administrative and General Expense (I) Transmission Support Expense, and(J) Transmission Related Taxes and Fees Charge.

A. Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate.

1. Transmission Investment Base

The Transmission Investment Base will be the average balances of (a) Transmission Plant, plus (b) Transmission Related General Plant, plus (c) Transmission Plant Held for Future Use, plus (d) Transmission Related Construction Work in Progress, less (e) Transmission Related Depreciation Reserve, less (f) Transmission Related Accumulated Deferred Taxes, plus (g) Transmission Related Loss on Reacquired Debt, plus (h) Other Regulatory Assets/Liabilities, less (i) AFUDC Regulatory Liability, plus (j) Transmission Prepayments, plus (k) Transmission Materials and Supplies, plus (l) Transmission Related Cash Working Capital.

(a) Transmission Plant will equal the balance of Eversource's investment in Transmission Plant.

(b) Transmission Related General Plant shall equal Eversource's balance of investment in General Plant multiplied by the Transmission Wages and Salaries Allocation Factor.

(c) Transmission Plant Held for Future Use shall equal the balance of Transmission Plant Held for Future Use.

(d) Transmission Related Construction Work in Progress shall equal the portion of Eversource's investment in Transmission-related projects as recorded in FERC Account 107 consistent with Commission orders.

(e) Transmission Related Depreciation Reserve shall equal the balance of Total Transmission Depreciation Reserve, plus the balance of Transmission Related General Plant

Depreciation Reserve. Transmission Related General Plant Depreciation Reserve shall equal the product of General Plant Depreciation Reserve and the Transmission Wages and Salaries Allocation Factor.

(f) Transmission Accumulated Deferred Taxes shall equal Eversource's electric balance of Total Accumulated Deferred Income Taxes multiplied by the Plant Allocation Factor, less the transmission and general plant components of Dispatch Center Accumulated Deferred Income Taxes.

(g) Transmission Related Loss on Reacquired Debt shall equal Eversource's electric balance of Total Loss on Reacquired Debt multiplied by the Plant Allocation Factor.

(h) Other Regulatory Assets/Liabilities shall equal Eversource's electric balance of any deferred rate recovery of FAS 106 expense multiplied by the Transmission Wages and Salaries Allocation Factor, plus Eversource's electric balance of FAS 109 multiplied by the Plant Allocation Factor.

(i) AFUDC Regulatory Liability shall equal the unamortized balance of the capitalized AFUDC booked on Eversource's transmission projects as recorded in FERC Account 254 consistent with Commission orders.

(j) Transmission Prepayments shall equal Eversource's electric balance of Prepayments multiplied by the Transmission Wages and Salaries Allocation Factor.

(k) Transmission Materials and Supplies shall equal Eversource's electric balance of Transmission Plant Materials and Supplies.

(l) Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Transmission Operation and Maintenance Expense and Transmission Related Administrative and General Expense.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) Eversource's Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon the capital structure at the end of each year and will equal the sum of:

(i) the long term debt component, which equals the product of the actual weighted average embedded cost to maturity of Eversource's long-term debt then outstanding and the ratio that long-term debt is to Eversource's total capital.

(ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of Eversource's preferred stock then outstanding and the ratio that preferred stock is to Eversource's total capital.

(iii) the return on equity component, shall equal the product of Eversource's return on equity ("ROE") of 10.57% and the ratio that common equity is to Eversource's total capital.

(b) Federal Income Tax shall equal

[(A+[(C+B)/D]x (FT)] divided by (1-FT)

where FT is the Federal Income Tax Rate and A is the sum of the preferred stock component and the return on equity component, as determined in Sections II.A.2.(a)(ii) and (iii) above, B is Transmission Related Amortization of Investment Tax Credits, as determined in Section II.D., below, C is the Equity AFUDC component of Transmission Depreciation Expense, as defined in Section II.B., and D is Transmission Investment Base, as Determined in II.A.1., above.

(c) State Income Tax shall equal

[A+[(C+B)/D] + Federal Income Tax)x(ST)] divided by (1-ST)

where ST is the State Income Tax Rate, A is the sum of the preferred stock component and return on equity component determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section II.D. below, C is the equity AFUDC component of Transmission Depreciation Expense, as defined in Section II.B., D is the

Transmission Investment Base, as determined in II.A.1., above and Federal Income Tax is the rate determined in Section II.A.2.(b) above.

B. Transmission Depreciation Expense shall equal the sum of Depreciation Expense for Transmission Plant, plus an allocation of General Plant Deprecation Expense calculated by multiplying General Plant Depreciation Expense by the Transmission Wages and Salaries Allocation Factor, less the amortization of AFUDC Regulatory Credit as recorded in Account 407.4, less the transmission plant and general plant components of Dispatch Center Depreciation Expense.

C. Transmission Related Amortization of Loss on Reacquired Debt shall equal Eversource's electric Amortization of Loss on Reacquired Debt multiplied by the Plant Allocation Factor.

D. Transmission Related Amortization of Investment Tax Credits shall equal Eversource's electric Amortization of Investment Tax Credits multiplied by the Plant Allocation Factor less the transmission plant and general plant components of Dispatch Center Amortization of Investment Tax Credits.

E. Transmission Related Municipal Tax Expense shall equal Eversource's electric Total Municipal Tax Expense multiplied by the Plant Allocation Factor, less the transmission plant and general plant components of Dispatch Center Municipal Tax Expense.

F. Transmission Related Payroll Tax Expense shall equal Eversource's electric Payroll Tax expense, multiplied by the Transmission Wages and Salaries Allocation Factor.

G. Transmission Operation and Maintenance Expense shall equal Transmission Operation and Maintenance Expenses.

H. Transmission Related Administrative and General Expenses shall equal the sum of (1) Eversource's Administrative and General Expenses multiplied by the Transmission Wages and Salaries Allocation Factor, (2) Property Insurance multiplied by the Transmission Plant Allocation Factor, (3) Expenses included in Account 928 (excluding Merger-Related Costs included in Account 928) related to FERC Assessments multiplied by the Plant Allocation Factor, plus any other Federal and State transmission related expenses or assessments in Account 928 plus specific transmission related expenses included in Account 930.1, plus Transmission Merger-Related Costs and, (4) specific transmission related public education expenses included in Account 426.54.

I. <u>Transmission Support Expense</u> shall equal the expense paid by Eversource for transmission support.

J. <u>Transmission Related Taxes and Fees Charge</u> shall include any fee or assessment imposed by any governmental authority on service provided under this Local Service Schedule that is not specifically identified under any other section of this Local Service Schedule.

ATTACHMENT ES-I
ANNUAL LOCALIZED TRANSMISSION REVENUE REQUIREMENT

Attachment ES-I Methodology

This formula sets forth the method that Eversource will use to determine its annual total revenue requirements for each Localized Facility (“Localized Transmission Revenue Requirement”). Subsequent references in this formula to “Localized Facility” and “Localized Transmission Revenue Requirement” refer to the Localized Facility and Localized Facility Revenue Requirement for each individual Localized Transmission Project. Each Localized Facility is identified in Section 16.3.

The Localized Transmission Revenue Requirement will be calculated for an initial term for a Localized Facility commencing on the date of the New England System Operator’s Schedule 12C cost allocation determination for the Localized Facility and ending on the May 31st following the date approved by the Commission for including the costs of the Localized Facilities in this Attachment ES-I (“Initial Term”), and continuing thereafter for successive 12 month periods commencing each June 1st (“Rate Year”). The Localized Transmission Revenue Requirement for the Initial Term for a Localized Facility will be calculated based on the estimated cost of the Localized Facilities for such period, and will be charged to customers in equal monthly installments beginning on the date permitted by the Commission, and continuing through the end of the Initial Term. The Localized Transmission Revenue Requirement for the Initial Term for a Localized Facility will be trued up for the appropriate calendar year by June 30th of the succeeding year(s) based on actual costs for the Initial Term.

The Localized Transmission Revenue Requirement for a Localized Transmission Project for a Rate Year commencing after the Initial Term (and for succeeding Rate Years) will be an annual calculation based on the previous calendar year’s Localized Transmission Revenue Requirements, plus the forecasted revenue requirements of Localized Facilities to be placed in service in the upcoming Rate Year. Each June 30th,

the Localized Transmission Revenue Requirement in effect during the portion of the Rate Year that occurred in the previous calendar year will be trued-up based on actual costs from such previous calendar year.

The true-up information will be based on actual data, in lieu of allocated data if specifically identified in the FERC Form 1, or based on allocated data if such specific information is not identified. For a capital addition whose cost exceeds $20 million, Eversource will make rate base adjustments to estimates and in the true-up process to represent the estimated and actual in-service dates for the capital addition. Specifically, Eversource will adjust for transmission plant, accumulated depreciation and accumulated deferred taxes.

The Localized Transmission Revenue Requirement for Eversource that is based on data for calendar year 2004 or later shall include a Localized Incremental Return and Associated Income Taxes on Eversource's Localized PTF transmission plant investments placed in-service on or after January 1, 2004 (such investments referred to herein as "Localized Post-2003 PTF Investment"). The Localized Incremental Return and Associated Income Taxes for Localized Post-2003 Investment shall incorporate an incentive ROE adder of 100 basis points for plant investments placed in service by December 31, 2008 or as otherwise permitted in Docket Nos. ER04-157 et al. for any projects included in the Regional System Plan ("RSP"), and shall incorporate any incentive ROE adder approved by the FERC under Order No. 679 for other plant investments. The total ROE for any project, including any authorized ROE incentives for Post-2003 PTF Investment and any other incentive ROE approved by FERC under Order No. 679 shall be capped by the top of the applicable zone of reasonableness determined by FERC for the relevant period. The data used in determining Eversource's Localized Incremental Return and Associated Taxes for Localized Post-2003 Investment shall be based on actual data in lieu of allocated data if specifically identified in Eversource accounting records.

I. Definitions

Capitalized terms not otherwise defined in the Tariff and as used in this formula have the following definitions:

A. Allocation Factors

1. Localized Transmission Allocation Factor shall equal the ratio of Localized Transmission Plant in Service to total investment in Transmission Plant.

2. Total Localized Plant Allocation Factor shall equal the ratio of Localized Transmission Plant in Service to Total Plant in Service.

3. Transmission Wages and Salaries Allocation Factor shall equal the ratio of Eversource's Transmission-related direct wages and salaries, including those of affiliated companies, to Eversource's total direct wages and salaries, including those of affiliated companies, and excluding administrative and general wages and salaries.

B. Terms

Administrative and General Expense shall equal Eversource's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928 and 930.1 and excluding Merger-Related Costs included in FERC Account Nos. 920-935 (other than those in FERC Account Nos. 924, 928 and 930.1, which have already been excluded).

Amortization of Loss on Reacquired Debt shall equal Eversource's expenses as recorded in FERC Account No. 428.1.

Amortization of Investment Tax Credits shall equal Eversource's expenses as recorded in FERC Account No. 411.4.

Depreciation Expense for Localized Transmission Plant shall equal Eversource's Localized Facilities expenses as recorded in FERC Account No. 403.

Dispatch Center means CL&P’s CONVEX dispatch center.

Dispatch Center Plant shall equal CL&P’s gross plant balance for the Dispatch Center as recorded in FERC Account Nos. 350-359 and 389-399.

General Plant shall equal Eversource’s gross plant balance as recorded in FERC Account Nos. 389-399 less Dispatch Center general plant.

General Plant Depreciation Expense shall equal Eversource’s general plant expenses as recorded in FERC Account No. 403 less the portion of such expense for the Dispatch Center.

General Plant Depreciation Reserve shall equal Eversource’s general plant reserve balance as recorded in FERC Account No. 108 less the portion of such reserve for the Dispatch Center.

Merger-Related Costs shall equal Eversource’s amortized merger-related costs as authorized by FERC or by state regulatory order.

Payroll Taxes shall equal those payroll expenses as recorded in Eversource’s FERC Account Nos. 408.1 and 409.1.

Prepayments shall equal Eversource’s prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal Eversource’s expenses as recorded in FERC Account No. 924.

Total Accumulated Deferred Income Taxes shall equal the net of Eversource’s deferred tax balance as recorded in FERC Account Nos. 281-283 and Eversource’s deferred tax balance as recorded in FERC Account No. 190.

Total Loss on Reacquired Debt shall equal Eversource’s expenses as recorded in FERC Account 189.

Total Municipal Tax Expense shall equal Eversource’s expenses as recorded in FERC Account Nos. 408.1, 409.1.

Transmission Merger-Related Costs shall equal Eversource's amortized merger-related transmission costs as authorized by FERC.

Localized Transmission Plant in Service shall equal Eversource's Localized Facilities gross plant balance as recorded in FERC Account Nos. 350-359.

Localized Transmission Plant Held for Future Use shall equal Eversource's Localized Facilities balance as recorded in FERC Account 105.

Localized Transmission Depreciation Reserve shall equal Eversource's Localized Facilities reserve balance as recorded in FERC Account 108.

Transmission Operation and Maintenance Expense shall equal Eversource's expenses as recorded in FERC Account Nos. 560, 561.5 – 561.8, 562-564 and 566-576.5 and shall exclude all HQ HVDC expenses booked to accounts 560 through 576.5 and expenses already included in Transmission Support Expense, as described in Section I below, which are included in FERC Account Nos. 560-576.5.

Transmission Plant shall equal Eversource's gross plant balance as recorded in FERC Account Nos. 350-359.

Transmission Plant Materials and Supplies shall equal Eversource's balance as assigned to transmission, as recorded in FERC Account 154.

Total Plant in Service shall equal Eversource's total gross plant balance as recorded in FERC Account Nos. 301-399.

II. Calculation of Localized Transmission Revenue Requirements

The Localized Transmission Revenue Requirements shall equal the sum of Eversource's (A) Localized Return and Associated Income Taxes (including the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment), (B) Localized Transmission Depreciation Expense, (C) Localized Transmission Related Amortization of Loss on Reacquired Debt, (D) Localized Transmission Related Amortization of Investment Tax Credits, (E) Localized Transmission Related Municipal Tax Expense, (F) Localized Transmission Related Payroll Tax Expense, (G) Localized Transmission Operation and

Maintenance Expense, (H) Localized Transmission Related Administrative and General Expense , (I) Localized Transmission Support Expense, and (J) Localized Transmission Related Taxes and Fees Charge. The Localized Incremental Return and Associated Income Taxes for Localized Post-2003 PTF Investment for Eversource shall be calculated using the investment base components specifically identified in Section A.1 of the formula below.

A. Localized Return and Associated Income Taxes shall equal the product of the Localized Transmission Investment Base and the Cost of Capital Rate. To calculate the Localized Incremental Return and Associated Income Taxes for Localized Post-2003 PTF Investment, Localized Transmission Plant will only include Sections II.A.1.(a), (c), and (d), in the manner indicated.

1. Localized Transmission Investment Base

The Localized Transmission Investment Base will be the average balances of (a) Localized Transmission Plant, plus (b) Localized Transmission Plant Held for Future Use less (c) Localized Transmission Related Depreciation Reserve, less (d) Localized Transmission Related Accumulated Deferred Taxes, plus (e) Localized Transmission Related Loss of Reacquired Debt, plus (f) Localized Transmission Prepayments, plus (g) Localized Transmission Materials and Supplies, plus (h) Localized Transmission Related Cash Working Capital.

(a) Localized Transmission Plant will equal the balance of (1) Eversource's investment in Localized Transmission Plant plus, (2) Eversource's balance of investment in General Plant multiplied by the Transmission Wages and Salaries Allocation Factor, further multiplied by the Localized Transmission Allocation Factor. In order to calculate the Localized Incremental Return and Associated Income Taxes for Localized Post-2003 PTF Investment, Localized Post-2003 PTF Transmission Plant shall be separately identified.

(b) Localized Transmission Plant Held for Future Use shall equal Eversource's balance of Localized Transmission Plant Held for Future Use.

(c) Localized Transmission Related Depreciation Reserve shall equal the balance of Localized Transmission Depreciation Reserve plus the balance of Localized Transmission Related General Plant Depreciation Reserve. Localized Transmission Related General Plant Depreciation Reserve shall equal the product of General Plant Depreciation Reserve and the Transmission Wages and Salaries Allocation Factor, further multiplied by the Localized

Transmission Allocation Factor. In order to calculate the Localized Incremental Return and Associated Income Taxes for Localized Post-2003 PTF Investment, Localized Transmission Related Depreciation Reserve associated with Localized Post-2003 PTF Investment shall equal Eversource's balance of Localized Transmission Depreciation Reserve.

(d) Localized Transmission Related Accumulated Deferred Taxes shall equal Eversource's electric balance of Total Accumulated Deferred Income Taxes, multiplied by the Total Localized Plant Allocation Factor. To calculate the Localized Incremental Return and Associated Income Taxes for Localized Post-2003 PTF Investment, Localized Transmission Related Accumulated Deferred Taxes associated with Localized Post-2003 PTF Investment shall equal Eversource's electric balance of Total Accumulated Deferred Income Taxes multiplied by the Total Localized Plant Allocation Factor.

(e) Localized Related Loss on Reacquired Debt shall equal Eversource's electric balance of Total Loss on Reacquired Debt multiplied by the Total Localized Plant Allocation Factor.

(f) Localized Transmission Prepayments shall equal Eversource's electric balance of Prepayments multiplied by the Transmission Wages and Salaries Allocation Factor and further multiplied by the Localized Transmission Allocation Factor.

(g) Localized Transmission Materials and Supplies shall equal Eversource's electric balance of Transmission Plant Materials and Supplies multiplied by the Localized Transmission Allocation Factor.

(h) Localized Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of (i) Localized Transmission Operation and Maintenance Expense, plus (ii) Localized Administrative and General Expense.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) Eversource's Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon the average capital structure and will equal the sum of:

(i) the long term debt component, which equals the product of the actual weighted average embedded cost to maturity of Eversource's long-term debt then outstanding and the ratio that long-term debt is to Eversource's total capital.

(ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of Eversource's preferred stock then outstanding and the ratio that preferred stock is to Eversource's total capital.

(iii) the return on equity component shall equal the product of Eversource's return on equity ("ROE") of 11.07% and the ratio that common equity is to Eversource's total capital. In order to calculate the Localized Incremental Return and Associated Taxes for Post-2003 PTF Investment, the Localized Incremental Return on Equity shall be the product of (1) Eversource's incremental return on equity of 1% for transmission plant investments associated with projects included in the RSP and placed in service by December 31, 2008 or otherwise permitted in Docket Nos. ER04-157 et al., and (2) any ROE incentive adder approved by the FERC under Order No. 679 for other transmission plant investments, provided that the total ROE for any project, including any such ROE incentives, shall be capped by the top of the applicable zone of reasonableness determined by FERC for the relevant period; and (3) the ratio of that common equity to total capital.[1]

(b) Federal Income Tax shall equal

[(A+[(C+B)/D]) x (FT)] divided by (1-FT)

where FT is the Federal Income Tax Rate and A is the sum of the preferred stock component and the return on equity component, as determined in Sections II.A.2.(a)(ii) and (iii) above, B is Localized Transmission Related Amortization of Investment Tax Credits, as determined in Section II.D., below, C is the Equity AFUDC component of Localized Transmission Depreciation Expense, as defined in Section II.B., and D is Localized Transmission Investment Base, as Determined in II.A.1., above.

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1 FERC Form-730 contains a list of transmission projects for which FERC has granted incentives under Order No. 679.

(c) State Income Tax Shall equal:

[(A+[(C+B)/D] + Federal Income Tax) x (ST)] divided by (1-ST)

where ST is the State Income Tax Rate, A is the sum of the preferred stock component and return on equity component determined in Sections II.A.2.(a)(ii) and (iii) above, B is the

Localized Transmission Related Amortization of Investment Tax Credits as determined in Section II.D. below, C is the equity AFUDC component of Localized Transmission Depreciation Expense, as defined in Section II.B., D is the Localized Transmission Investment Base, as determined in II.A.1. above and Federal Income Tax is the rate determined in Section II.A.2.(b) above.

B. Localized Transmission Depreciation Expense shall equal the sum of Depreciation Expense for Localized Transmission Plant, plus an allocation of General Plant Deprecation Expense calculated by multiplying General Plant Depreciation Expense by the Transmission Wages and Salaries Allocation Factor and further multiplied by the Localized Transmission Allocation Factor.

C. Localized Transmission Related Amortization of Loss on Reacquired Debt shall equal Eversource's electric Amortization of Loss on Reacquired Debt multiplied by the Total Localized Plant Allocation Factor.

D. Localized Transmission Related Amortization of Investment Tax Credits shall equal Eversource's electric Amortization of Investment Tax Credits multiplied by the Total Localized Plant Allocation Factor.

E. Localized Transmission Related Municipal Tax Expense shall equal Eversource's Total Municipal Tax Expense multiplied by the Total Localized Plant Allocation Factor.

F. Localized Transmission Related Payroll Tax Expense shall equal Eversource's electric Payroll Taxes expense, multiplied by the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Localized Transmission Allocation Factor.

G. <u>Localized Transmission Operation and Maintenance Expense</u> shall equal Eversource's Transmission Operation and Maintenance Expense multiplied by the Localized Transmission Allocation Factor.

H. <u>Localized Transmission Related Administrative and General Expense</u> shall equal the sum of (1) Eversource's Administrative and General Expense multiplied by the Transmission Wages and Salaries Allocation Factor and further multiplied by the Localized Transmission Allocation Factor, (2) Property Insurance multiplied by the Total Localized Plant Allocation Factor, (3) Expenses included in Account 928 (excluding Merger-Related Costs included in Account 928) related to FERC Assessments multiplied by the Total Localized Plant Allocation Factor, (4) Federal and State transmission related expenses or assessments in Account 928 multiplied by the Localized Transmission Allocation Factor, (5) specific transmission related expenses included in Account No. 930.1, multiplied by the Localized Transmission Allocation Factor, plus Transmission Merger-Related Costs multiplied by the Localized Transmission Allocation Factor and (6) specific Localized Facility related public education expenses included in Account 426.54.

I. <u>Transmission Support Expense</u> shall equal the expense paid by Eversource for transmission support for Localized Facilities.

J. <u>Transmission Related Taxes and Fees Charge</u> shall include any fee or assessment imposed by any governmental authority on transmission service provided under this Local Service Schedule that is not specifically identified under any other section of this Local Service Schedule, multiplied by the Localized Transmission Allocation Factor.

SCHEDULE 21-ES

ATTACHMENT ES-L

Creditworthiness Procedures

1. **General Information**

All customers taking any service under Schedule 21-ES, the Local Service Schedule ("LSS"), and the associated schedules of The Connecticut Light and Power Company, Western Massachusetts Electric Company, and Public Service Company of New Hampshire ("Eversource") must meet the terms of this Attachment ES-L.

2. **Establishing Creditworthiness**

a) Each customer's creditworthiness must be established before receiving transmission services from Eversource. A customer will be evaluated at the time that its application for transmission service is provided to Eversource based on the creditworthiness information required under this Attachment ES-L. Eversource shall conduct a credit review of each Transmission Customer not less than annually or upon reasonable request by the Transmission Customer.

b) Eversource will review the customer's creditworthiness information for completeness and will notify the customer if additional information is required.

c) Upon completion of a creditworthiness evaluation of a customer, Eversource will forward a written evaluation to the customer if they determine that Financial Assurance must be provided.

3. Financial Information

Customers requesting transmission service must submit if available the following:

a) All current rating agency reports of the customer from Standard and Poor's ("S&P"), Moody's Investors Service ("Moody's"), and/or Fitch Ratings ("Fitch").

b) A Management Discussion and Analysis ("MD&A") along with audited financial statements provided by an independent registered public accounting firm or a registered

independent auditor for the three (3) most recent fiscal years, or the period of the customer's existence, if shorter than three (3) years.

4. Creditworthiness – Qualification for Unsecured Credit

a) A customer may receive unsecured credit from Eversource equivalent to three (3) months of the transmission charges. The customer must meet at least one of the following criteria:

(i) If rated, the customer's lowest rating from the three rating agencies on its senior unsecured long-term debt; or if the customer does not have such a rating, then one rating level below the rating then assigned to the customer's corporate credit rating, as follows:

1. a Standard and Poor's or Fitch rating of at least BBB, or

2. a Moody's rating of least Baa2.

(ii) If un-rated or if rated below BBB/Baa2, as described in 4(a)(i) above, the customer must meet all of the following creditworthiness criteria for the three (3) most recent fiscal years:

1. A Capitalization Ratio (Debt divided by the sum of shareholders' equity and Debt) of no more than 60 percent Debt, where "Debt" is defined as the sum of all long-term and short-term debt, preferred securities and capital leases. Each of which is recorded in accordance with generally accepted accounting principles;

2. Earnings before interest, taxes, depreciation and amortization ("EBITDA") in the most recent fiscal quarter divided by interest expense (ratio of EBITDA-to-interest expense of at least three (3) times); and

3. Audited Financial Statements with an unqualified auditor opinion.

b) If the customer relies on the creditworthiness of a parent company, the parent company must satisfy the ratings criteria in Section 4(a) above, and must provide to Eversource a written

guarantee that it will be unconditionally responsible for all financial obligations associated with the customer's receipt of transmission service from Eversource.

c) If the customer or the customer's parent company do not qualify for unsecured credit under Sections 4(a) or (b) above, the customer can still qualify for unsecured credit equivalent to three (3) months of transmission service charges, if:

(i) the customer has, on a rolling basis, 12 consecutive months of payments to Eversource with no missed, late or defaults in payment; or

(ii) the customer has an executed long-term contract for the sale of the full output (energy and capacity) of its generating unit and either has executed a corresponding service transmission service agreement under Schedule 21-ES for the transmission of that output or the execution of such agreement is pending the customer's demonstration of creditworthiness.

5. Financial Assurance

If the customer does not meet the applicable requirements for unsecured credit set out in Section 4 then the customer must either:

a) pay in advance an amount equal to the lesser of the total charge for transmission service not less than five (5) days in advance of the commencement of service, in which case Eversource will pay to the customer interest on the amounts not yet due to Eversource, computed in accordance with 18 C.F.R. §35.19(a)(2)(iii) of the Commission's Regulations; or

b) obtain Financial Assurance in the form of a letter of credit or a parent guarantee equal to the equivalent of three (3) months of transmission service charges prior to receiving service.

(i) The letter of credit must be one or more irrevocable, transferable standby letters of credit issued by a United States commercial bank or a United States branch of a foreign bank provided that such customer is not an affiliate of such bank. The issuing bank must have a credit rating of at least A2 from Moody's or an A rating from S&P or Fitch, or an equivalent credit rating by another nationally recognized rating service reasonably acceptable to Eversource, provided that such bank shall have assets totaling not less than

ten billion dollars ($10,000,000,000). All costs of the letter of credit shall be borne by the applicant for such letter of credit. In the event of an inconsistency in the ratings by Moody's, S&P, or Fitch, a "split rating", the lowest credit rating shall apply.

(ii) If the credit rating of a bank or other financial institution issuing a letter of credit to a customer falls below the levels specified in Section 5(b)(i) above, the customer shall have three (3) business days to obtain a suitable letter of credit from another bank or other financial institution that meets the specified levels unless Eversource agrees in writing to extend such period.

6. Notifications

Each customer must inform Eversource in writing within three (3) business days of any material change in its or its letter of credit issuer's financial condition, and if the customer qualifies under Section 4(b), that of its parent company. A material change in financial condition may include, without limitation, the following:

a) change in ownership by way of a merger, acquisition, or substantial sale of assets;
b) downgrade by a recognized major financial rating agency;
c) placement on credit watch with negative implications by a major financial rating agency;
d) a bankruptcy filing by the customer or parent;
e) any action requiring the filing of a SEC Form 8-K;
f) declaration of or acknowledgement of insolvency;
g) report of a significant quarterly loss or decline in earnings;
h) resignation of key officer(s); or
i) issuance of a regulatory order and/or the filing of a lawsuit that could materially adversely impact current or future financial results.

7. Ongoing Financial Review

Each customer is required to submit to Eversource annually or when issued, as applicable:

a) current rating agency reports;
b) audited financial statements from an independent registered public accounting firm or a registered independent auditor; and
c) SEC Forms 10-K and 8-K, promptly upon their filing.

8. Change in Creditworthiness Status

A customer who has been extended unsecured credit pursuant to Section 4, must comply with the terms of Financial Assurance in Section 5, if one or more of the following conditions apply:

a) the customer no longer meets the applicable criteria for unsecured credit in Section 4;

b) the customer exceeds the amount of unsecured credit extended by Eversource, in which case Financial Assurance equal to the amount of exceeded unsecured credit must be provided within five (5) business days; or

c) the customer has missed two or more payments for any of the transmission services provided by Eversource in the last twelve (12) months.

9. Procedures for Changes in Credit Levels and Collateral Requirements

a) Eversource shall issue notice to a customer of any changes to the approved credit levels and/or collateral requirements within five (5) business days after (1) receiving notification of any material changes in financial condition under Section 6 above; (2) receiving the information required for the customer's ongoing financial review listed in Section 7 above; or (3) the occurrence of any of the events leading to a change in creditworthiness requirements listed in Section 8 above.

b) A customer may submit a written request that Eversource provide an explanation of the reasons for the changes in credit levels and/or collateral requirements within five (5) business days after receiving notification of the changes. Eversource will provide a written response within five (5) business days after receiving such a request.

10. Contesting Creditworthiness Determinations

A customer may contest Eversource's determination of its creditworthiness by submitting a written request for re-evaluation within 20 calendar days of being notified of the creditworthiness determination. The request should provide information supporting the basis for a re-evaluation of the customer's creditworthiness. Eversource will review the request and respond within 20 calendar days of receipt.

11. Process for Changing Credit Requirements

a) In the event Eversource plans to revise the Schedule 21-ES requirements for credit levels or collateral requirements described in this Attachment ES-L, they will make a filing under Section 205 of the Federal Power Act.

b) Eversource shall provide written notification to ISO-NE and stakeholders of any filing described above, at least 30 days in advance of such filing.

c) Filing notifications shall include a detailed description of the filing, including a redlined document containing revised changes(s) to this Attachment ES-L.

d) Eversource shall consult with interested stakeholders upon request.

e) Following Commission acceptance of such filing and upon the effective date, Eversource shall revise its Attachment ES-L an updated version of Schedule 21-ES shall be posed to the ISO-NE web site.

f) When Eversource changes its credit requirements for service under Schedule 21-ES, the customer is responsible for forwarding updated financial information to Eversource. The customer must indicate whether the change affects its ability to meet the requirements of Attachment ES-L. In cases where the customer’s credit status has changed, the customer must take the necessary steps to comply with the revised credit requirements of Attachment ES-L by the effective date of the change.

12. Suspension of Service

Eversource may immediately suspend service (with notification to the Commission) to a customer, and may initiate proceedings with the Commission to terminate service, if the customer does not meet the terms described in Sections 4 through 8 at any time during the term of service or if the customer’s payment obligations to Eversource exceed the amount of unsecured or secured credit to which it is entitled under this Attachment ES-L. A customer is not obligated to pay for transmission service that is not provided as a result of a suspension of service.

ATTACHMENT F
ANNUAL TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirements for each PTO will reflect the PTO's costs with respect to Pool Supported PTF and the HTF, including costs attributable to those PTOs deemed to own or support PTF pursuant to Section II.49 of the Tariff. The Transmission Revenue Requirements will be an annual calculation based on the previous year's calendar data as shown, in the case of PTOs that are subject to the Commission's jurisdiction, in the PTO's FERC Form 1 report for that year; provided, however, that if a PTO is deemed to own or support PTF pursuant to Section II.49 of the Tariff, such PTO may include the costs as incurred by its Related Person for PTF facilities and Transmission Support Expenses as the basis for establishing its initial and subsequent Annual Transmission Revenue Requirements, only until such PTO has a full calendar year of cost data under its ownership. Such PTO's costs will be determined from FERC Form 1 data if available, or if not available, from other supporting data certified by an auditor of the PTO or Related Person, and in a format comparable to that used to report such costs in FERC Form 1. Such costs shall be based on actual data in lieu of allocated data if specifically identified in the Form 1 report in accordance with the following formula and Schedule 12:

I. The Transmission Revenue Requirement shall equal the sum of the PTO's (A) Return and Associated Income Taxes, (B) Transmission Depreciation and Amortization Expense, (C) Transmission Related Amortization of Loss on Reacquired Debt, (D) Transmission Related Amortization of Investment Tax Credits, (E) Transmission Related Municipal Tax Expense, (F) Transmission Related Payroll Tax Expense, (G) Transmission Operation and Maintenance Expense, (H) Transmission Related Administrative and General Expense, (I) Transmission Related Integrated Facilities Charges, minus (J) Transmission Support Revenue, plus (K) Transmission Support Expense, plus (L) Transmission Related Expense from Generators, plus (M) Transmission Related Taxes and Fees Charge, minus (N) Revenue for Short-Term service under the OATT and (O) Transmission Rents Received from Electric Property.

The details for implementation of Attachment F, as well as the definitions of the terms used in the Attachment F formula, shall be established in accordance with the Attachment F Implementation Rule contained in this OATT.

ATTACHMENT F
IMPLEMENTATION RULE

This rule sets forth details with respect to the determination each year of the Transmission Revenue Requirements for each PTO. Such Transmission Revenue Requirements shall reflect the PTO's costs for Pool Transmission Facilities ("PTF") and the Highgate Transmission Facilities ("HTF"), including costs attributable to those PTOs deemed to own or support PTF pursuant to Section II.49 of the Tariff. The Transmission Revenue Requirements for each PTO will reflect the PTO's costs with respect to Pool Supported PTF and the HTF. The Transmission Revenue Requirements will be an annual calculation based on the previous year's calendar data as shown, in the case of PTOs which are subject to the Commission's jurisdiction, in the PTO's FERC Form 1 report for that year; provided, however, that if a PTO is deemed to own or support PTF, such PTO may include the costs as incurred by its Related Person for PTF facilities and Transmission Support Expenses as the basis for establishing its initial and subsequent Annual Transmission Revenue Requirements, only until such PTO has a full calendar year of cost data under its ownership. Such PTO's costs will be determined from FERC Form 1 data if available, or if not available, from other supporting data certified by an auditor of the PTO or Related Person, and in a format comparable to that used to report such costs in FERC Form 1. Such costs shall be based on actual data in lieu of allocated data if specifically identified in the Form 1 report in accordance with the following formula and Schedule 12. The HTF Transmission Revenue Requirements shall be subject to the limitations of inclusion of such costs as set forth in Appendix B to this Attachment. The owners of the HTF, or their designated agent, will submit the annual HTF Transmission Revenue Requirements calculation based on the previous calendar year's cost data from their FERC Form 1 or equivalent information from their official books and records, as appropriate.

The Post-96 Transmission Revenue Requirement for each PTO that is based on data for calendar year 2004 or later shall include an Incremental Return and Associated Income Taxes on the PTO's PTF transmission plant investments included in the Regional System Plan and placed in-service on or after January 1,2004 (such investments referred to herein as "Post-2003 PTF Investment"). The Incremental Return and Associated Income Taxes for Post-2003 PTF Investment shall incorporate an incentive ROE adder of 100 basis points for plant investment placed in service by December 31, 2008 or as otherwise permitted in Docket Nos. ER04-157, et al. for any projects included in the RSP, and shall incorporate any incentive ROE adder approved by the FERC under Order No. 679 for other plant investments and for MPRP CWIP and NEEWS CWIP. The total ROE for any project, including any authorized ROE incentives for Post-2003 PTF Investment and any other incentive ROE approved by FERC under Order

No. 679 shall be capped by the top of the applicable zone of reasonableness determined by FERC for the relevant period. The data used in determining each PTO's Incremental Return and Associated Taxes for Post-2003 Investment shall be based on actual data in lieu of allocated data if specifically identified in the PTO's accounting records.

The Post-1996 Pool PTF Rate, as calculated pursuant to Schedule 9, shall include for each PTO a Forecasted Transmission Revenue Requirement calculated in accordance with Appendix C to this Attachment F Implementation Rule. Additionally, the Pre-1997 and Post-1996 Pool PTF Rates shall include an Annual True-up calculated in accordance with Appendix C to this Attachment F Implementation Rule.

The PTOs shall make an annual informational filing on or before July 31 of each year showing the Pool PTF Rate in effect for the period beginning June 1 of that year through May 31 of the subsequent year.Further, the informational filing with respect to the determination of the Pool PTF Rate will include a breakdown by PTO of the amount of the change in PTF and HTF investment during the prior year and the PTF and HTF retirements or additions causing such change to beginning and end-of-year PTF balances and HTF balances (although beginning-of-year PTF balances and HTF balances are not used in the formula itself), and any additions to PTF and HTF, retirements of PTF and HTF, and reclassifications of PTF and HTF during the year for each PTO. If there are any corrections made to the information reflected in the informational filing after it has been submitted, the PTOs will file corrections to the informational filing. At least forty-five days before the informational filing is made with the Commission, the PTOs shall make available to Transmission Customers and any other interested parties a draft of the proposed filing for review and comment prior to the filing by posting such draft on the ISO website. The filing of the information filing does not re-open the formula rate set forth below for review, but rather is contestable only with respect to the accuracy of the information contained in the informational filing.

The ISO shall have the discretion to conduct audits of such charges, with advisory Stakeholder input on the scope of audit, including on any agreed-upon procedures to be used by the auditor. In this provision, the term “agreed-upon procedures” shall have the meaning afforded to it by the American Institute of Certified Public Accountants.

I. DEFINITIONS

Capitalized terms not otherwise defined in the Tariff and as used in this rule have the following definitions:

A. ALLOCATION FACTORS

1. Transmission Wages and Salaries Allocation Factor shall equal the ratio of Transmission-related direct wages and salaries including those of affiliated Companies to the PTO's total direct wages and salaries including those of the Affiliates' Companies and excluding administrative and general wages and salaries.

2. PTF/HTF Transmission Plant Allocation Factor shall equal the ratio of PTF/HTF Transmission Plant to Total Investment in Transmission Plant, excluding capital leases in the Phase I/II HVDC-TF (Phase I/II HVDC-TF Leases).

3. Plant Allocation Factor shall equal the ratio of the sum of Total Investment in Transmission Plant, excluding Phase I/II HVDC-TF Leases, and Transmission Related Intangible and General Plant to Total Plant in service excluding Phase I/II HVDC-TF Leases.

B. TERMS

Administrative and General Expense shall equal the PTO's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928 and 930.1 and excluding Merger-Related Costs included in FERC Account Nos. 920-935 (other than those in FERC Account Nos. 924, 928 and 930.1, which have already been excluded).

Amortization of Loss on Reacquired Debt shall equal the PTO's expenses as recorded in FERC Account No. 428.1.

Amortization of Investment Tax Credits shall equal the PTO's credits as recorded in FERC Account No. 411.4.

Depreciation Expense for Transmission Plant shall equal the PTO's transmission expenses as recorded in FERC Account No. 403.

General Plant shall equal the PTO's gross plant balance as recorded in FERC Account Nos. 389-399.

General Plant Depreciation and Amortization Expense shall equal the PTO's general expenses as recorded in FERC Account No. 403 and NSTAR Electric's FERC Account No. 404 for items subject to amortization.

General Plant Amortization Reserve shall equal NSTAR Electric's general reserve balance as recorded in FERC Account No. 111.

HTF Transmission Plant shall equal the PTO's balance of investment in the Highgate Transmission Facilities as recorded in FERC Account Nos. 350-359.

Intangible Plant shall equal NSTAR Electric's gross plant balance as recorded in FERC Account No. 303. The only allowable Intangible Plant for inclusion are software, patent or rights costs.

Intangible Plant Amortization Expense shall equal NSTAR Electric's amortization expenses as recorded in FERC Account Nos. 404-405. The only allowable Intangible Plant Amortization Expense for inclusion is the amortization of software, patent or rights costs.

Intangible Plant Amortization Reserve shall equal NSTAR Electric's amortization reserve balance as recorded in FERC Account No. 111. The only allowable Intangible Plant Amortization Reserve for inclusion is that related to the amortization of software, patent or rights costs.

Maine Power Reliability Program Construction Work In Progress ("MPRP CWIP") shall equal Central Maine Power Company's ("CMP's") MPRP CWIP balance as recorded in FERC Account No. 107 for costs determined to be Pool- Supported PTF in accordance with Schedule 12 of this OATT.

Merger-Related Costs shall equal NSTAR Electric Company's ("NSTAR Electric"), CL&P's, Public Service Company of New Hampshire's ("PSNH") and WMECO's amortized merger-related costs as authorized by FERC or by state regulatory order.

New England East-West Solution Construction Work in Progress ("NEEWS CWIP") shall equal the NEEWS CWIP balances of The Connecticut Light and Power Company ("CL&P") and Western Massachusetts Electric Company ("WMECO") and New England Power Company ("NEP") as recorded in FERC Account No. 107 for costs determined to be Pool-Supported PTF in accordance with Schedule 12 of this OATT.

Other Regulatory Assets/Liabilities - FAS 106 shall equal the net of the PTO's FAS 106 balance as recorded in FERC Account 182.3 and any FAS 106 balance as recorded in the PTO's FERC Account No. 254.

Other Regulatory Assets/Liabilities - FAS 109 shall equal the net of the PTO's FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in the PTO's FERC Account No. 254.

Payroll Taxes shall equal those payroll expenses as recorded in the PTO's FERC Account Nos. 408.1.

Phase I/II HVDC-TF Leases shall equal the PTO's balance in capital leases as recorded in FERC Account Nos. 350-359 and FERC Account Nos. 389-399.

Plant Held for Future Use shall equal the PTO's balance in FERC Account No.105.

Prepayments shall equal the PTO's prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal the PTO's expenses as recorded in FERC Account No. 924.

PTF Transmission Plant shall equal the PTO's transmission plant as defined in the Section II.49 of the OATT and determined in accordance with Appendix A of this Rule, which is entitled "Rules for Determining Investment To be Included in PTF."

PTF/HTF Transmission Plant Investment shall equal the PTO's (a) PTF Transmission Plant plus (b) HTF Transmission Plant.

Total Accumulated Deferred Income Taxes shall equal the net of the PTO's deferred tax balance as recorded in FERC Account Nos. 281-283 and the PTO's deferred tax balance as recorded in FERC Account No. 190.

Total Loss on Reacquired Debt shall equal the PTO's expenses as recorded in FERC Account 189.

Total Municipal Tax Expense shall equal the PTO's municipal tax expenses as recorded in FERC Account Nos. 408.1.

Total Plant in Service shall equal the PTO's total gross plant balance as recorded in FERC Account Nos. 301-399.

Total Transmission Depreciation Reserve shall equal the PTO's transmission reserve balance as recorded in FERC Account 108.

Transmission Merger-Related Costs shall equal NSTAR Electric's, CL&P's, PSNH's and WMECO's amortized merger-related transmission costs as authorized by FERC.

Transmission Operation and Maintenance Expense shall equal the PTO's expenses as recorded in FERC Account Nos. 560, 561.5-561.8, 562-564 and 566-573, and shall exclude all Phase I/II HVDC-TF expenses booked to accounts 560 through 573 and expenses already included in Transmission Support Expense, as described in Section K which are included in FERC Account Nos. 560-573.

Transmission Plant shall equal the PTO's Gross Plant balance as recorded in FERC Account Nos. 350-359.

Transmission Plant Materials and Supplies shall equal the PTO's balance as assigned to transmission, as recorded in FERC Account No. 154.

II. CALCULATION OF TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirement shall equal the sum of the PTO's (A) Return and Associated Income Taxes (including the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP), (B) Transmission Depreciation and Amortization Expense, (C) Transmission Related Amortization of Loss on Reacquired Debt, (D) Transmission Related Amortization of Investment Tax Credits, (E) Transmission Related Municipal Tax Expense, (F) Transmission Related Payroll Tax Expense, (G) Transmission Operation and Maintenance Expense, (H) Transmission Related Administrative and General Expenses, (I) Transmission Related Integrated Facilities Charges, minus (J) Transmission Support Revenue, plus (K) Transmission Support Expense, plus (L) Transmission-Related Expense from Generators, plus (M) Transmission Related Taxes and Fees Charge, minus (N) Revenue for Short-Term service under the OATT, (O) Transmission Rents Received from Electric Property and (P) Transmission Revenues from MEPCO Grandfathered Transmission Service Agreements. The Incremental Return and Associated Income Taxes for Post-2003 PTF Investment for each PTO shall be calculated using the investment base components specifically identified in Section A. 1 of the formula below.

A. <u>Return and Associated Income Taxes</u> shall equal the product of the Transmission Investment Base and the Cost of Capital Rate. To calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP, Transmission Investment Base will only include Sections II.A. 1 .(a), (d), (e), (k), and (1) in the manner indicated.

1. <u>Transmission Investment Base</u>

The Transmission Investment Base will be the year end balances of(a) PTF/HTF Transmission Plant, plus (b) Transmission Related Intangible and General Plant, plus (c) Transmission Plant Held for Future Use, less (d) Transmission Related Depreciation and Amortization Reserve, less (e) Transmission Related Accumulated Deferred Taxes, plus (f) Transmission Related Loss on Re.acquired Debt, plus (g) Other Regulatory Assets/Liabilities, plus (h) Transmission Prepayments, plus (i) Transmission Materials and Supplies, plus (j) Transmission Related Cash Working Capital, plus (k) MPRP CWIP, plus (l) NEEWS CWIP.

(a) <u>PTF Transmission Plant</u> will equal the balance of the PTO's PTF Investment in (a) Transmission Plant plus (b) HTF Transmission Plant. This value excludes (i) the PTO's Phase I/II HVDC-TF Leases, (ii) the portion of any facilities, the cost of which is directly assigned under Schedule 11 to the OATT, to the Transmission Customer or a Generator

Owner or Interconnection Requester, (iii) the Pre-1997 PTF gross plant investment associated with leased facilities occupied by the Phase II section of the Phase I/II HVDC-TF. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment, Post2003 PTF Transmission Plant shall be separately identified.

(b) Transmission Related Intangible and General Plant shall equal the sum of the PTO's balance of investment in Intangible Plant and General Plant multiplied by the Transmission Wages and Salaries Allocation Factor and the PTF/HTF Transmission Plant Allocation Factor.

(c) Transmission Plant Held for Future Use shall equal the PTO's balance of Transmission-related Plant Held for Future Use multiplied by the PTF/HTF Transmission Plant Allocation Factor.

(d) Transmission Related Depreciation and Amortization Reserve shall equal the PTO's balance of Total Transmission Depreciation Reserve, plus the balance of Transmission Related Intangible Plant Amortization Reserve, Transmission Related General Plant Depreciation Reserve and Transmission Related General Plant Amortization Reserve. Transmission Related Intangible Plant Amortization Reserve, Transmission Related General Plant Depreciation Reserve and Transmission Related General Plant Amortization Reserve shall equal the product of the sum of Intangible Plant Amortization Reserve, General Plant Depreciation Reserve and General Plant Amortization Reserve, and the Transmission Wages and Salaries Allocation Factor. This sum shall be multiplied by the PTF/HTF Transmission Plant Allocation Factor. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment, Transmission Depreciation Reserve associated with Post-2003 PTF Investment shall equal the PTO's balance of Total Transmission Depreciation Reserve multiplied by the ratio of Post-2003 PTF Transmission Plant to Total Investment in Transmission Plant, excluding capital leases in the Phase I/II HVDC-TF Leases.

(e) Transmission Related Accumulated Deferred Taxes shall equal the PTO's electric balance of Total Accumulated Deferred Income Taxes, multiplied by the Plant Allocation Factor, further multiplied by the PTF/HTF Transmission Plant Allocation Factor. To calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF

Investment, Transmission Related Accumulated Deferred Income Taxes associated with Post-2003 PTF Investment shall equal the PTO's balance of total property-related accumulated deferred income taxes as recorded in FERC accounts 281 and 282, multiplied by the ratio of Total Investment in Transmission Plant, excluding Phase I/II HVDC-TF Leases, to Total Plant in Service excluding Phase I/II HVDC-TF Leases, further multiplied by the ratio of Post-2003 PTF Transmission Plant to Total Investment in Transmission Plant, excluding Phase I/II HVDC-TF Leases.

(f) Transmission Related Loss on Reacquired Debt shall equal the PTO's electric balance of Total Loss on Reacquired Debt multiplied by the Plant Allocation Factor, further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

(g) Other Regulatory Assets/Liabilities shall equal the PTO's electric balance of any deferred rate recovery of FAS 106 expenses multiplied by the Transmission Wages and Salaries Allocation Factor, plus the PTO's electric balance of FAS 109 multiplied by the Plant Allocation Factor. This sum shall be multiplied by the PTF/HTF Transmission Plant Allocation Factor.

(h) Transmission Prepayments shall equal the PTO's electric balance of prepayments multiplied by the Transmission Wages and Salaries Allocation Factor and further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

(i) Transmission Materials and Supplies shall equal the PTO's electric balance of Transmission Plant Materials and Supplies, multiplied by the PTF/HTF Transmission Plant Allocation Factor.

(j) Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of the PTO's Transmission Operation and Maintenance Expense, Transmission Related Administrative and General Expense and Transmission Support Expense, to the extent that Transmission Support Expense exceeds Transmission Support Revenue included in Paragraph J of the formula.

(k) MPRP CWIP shall equal CMP's balance as recorded in FERC Account No. 107 for the MPRP as authorized by Commission order and in accordance with CMP's Accounting

Procedures for MPRP CWIP. In order to calculate the Incremental Return and Associated Income Taxes for MPRP CWIP, MPRP CWIP shall be separately identified.

(l) NEEWS CWIP shall equal CL&P, WMECO and NEP's balances as recorded in FERC Account No. 107 for the NEEWS as authorized by Commission order and in accordance with the companies' respective Accounting Procedures for NEEWS CWIP. In order to calculate the Incremental Return and Associated Income Taxes for NEEWS CWIP, NEEWS CWIP shall be separately identified.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) the PTO's Weighted Cost of Capital, plus (b) Federal Income Tax plus (e) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon the capital structure at the end of each year and will equal the sum of (i), (ii), and (iii) below. The Cost of Capital Rate to be used in calculating the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP, shall only reflect item (iii) below and shall apply in the manner indicated below.

(i) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity of the PTO's long-term debt then outstanding and the ratio that long-term debt is to the PTO's total capital.

(ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of the PTO's preferred stock then outstanding and the ratio that preferred stock is to the PTO's total capital.

(iii) the return on equity component, shall be the product of the allowed ROE of the PTO's common equity and the ratio that common equity is to the PTO's total capital. For pre-1997 and post-1996 assets, the ROE is 11.07%. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP, the incremental return on equity shall be the product of: (1) the PTO's incremental return on equity of 1.0% for plant investments associated with projects included in the RSP and placed in service by December 31, 2008 or otherwise permitted in Docket Nos. ER04-157, et al.; (2) any ROE incentive approved by the FERC under Order No. 679 for other plant investments and MPRP CWIP and NEEWS CWIP, provided that the total ROE for any project, including any such ROE incentives, shall be capped by the top of the applicable zone of reasonableness determined by FERC for the relevant period, and (3) the ratio that common equity is to the PTO's total capital) [1]

(b) Federal Income Tax shall equal

$$\frac{(A+[(C+B)/D])(FT)}{I-FT}$$

where FT is the Federal Income Tax Rate and A is the sum of the preferred stock component and the return on equity component, as determined in Sections ll.A.2.(a)(ii) and (iii) above, B is Transmission Related Amortization of Investment Tax Credits, as determined in Section II.D., below, C is the Equity AFUDC component of Transmission Depreciation Expense, as defined in Section ll.B., and D is Transmission Investment Base, as determined in Section II.A.1., above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP, the incremental Federal Income Tax shall equal

$$\frac{(A' * FT)}{(1 -FT)}$$

where FT is the Federal Income Tax Rate and A' is the incremental return on equity component, as determined in Section II.A.2.(a)(iii) above.

(c) State Income Tax shall equal

$$\frac{(A+[(C+B)/D] + \text{Federal Income Tax})(ST)}{1 -ST}$$

where ST is the State Income Tax Rate, A is the sum of the preferred stock component and return on equity component determined in Sections II.A.2.(a)(ii) and (iii) above, B is

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[1] FERC Form-730 contains a list of transmission projects for which FERC has granted incentives under Order No. 679.

the Amortization of Investment Tax Credits as determined in Section ll.D.below, C is the equity AFUDC component of Transmission Depreciation Expense, as defined in Section II.B.. D is the Transmission Investment Base, as determined in II.A.1., above and Federal Income Tax is the rate determined in Section II.A.2.(b) above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP, the incremental State Income Tax shall equal

$$\frac{(A' + \text{Federal Income Tax})(ST)}{(1 - ST)}$$

where ST is the State Income Tax Rate, A' is the incremental return on equity component determined in Section II.A.2.(a)(iii) above, and Federal Income Tax is the rate determined in Section II.A.2.(b) above.

B. <u>Transmission Depreciation and Amortization Expense</u> shall equal the PTF/HTF Transmission Plant Allocation Factor, multiplied by the sum of (i) the PTO's Depreciation Expense for Transmission Plant, plus (ii) an allocation of Intangible Plant Amortization Expense and (iii) General Plant Depreciation and Amortization Expense calculated by multiplying the sum of (a) Intangible Plant Amortization Expense and (b) General Plant Depreciation and Amortization Expense by the Transmission Wages and Salaries Allocation Factor.

C. <u>Transmission Related Amortization of Loss on Reacquired Debt</u> shall equal the PTO's electric Amortization of Loss on Reacquired Debt multiplied by the Plant Allocation Factor, and further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

D. <u>Transmission Related Amortization of Investment Tax Credits</u> shall equal the PTO's electric Amortization of Investment Tax Credits multiplied by the Plant Allocation Factor, and further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

E. <u>Transmission Related Municipal Tax Expense</u> shall equal the PTO's total electric municipal tax expense multiplied by the Plant Allocation Factor, and further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

F. Transmission Related Payroll Tax Expense shall equal the PTO's total electric payroll tax expense, multiplied by the Transmission Wages and Salaries Allocation Factor, further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

G. Transmission Operation and Maintenance Expense shall equal the PTO's Transmission Operation and Maintenance Expenses multiplied by the PTF/HTF Transmission Plant Allocation Factor.

H. Transmission Related Administrative and General Expenses shall equal the sum of the PTO's (1) Administrative and General Expenses multiplied by the Transmission Wages and Salaries Allocation Factor, (2) Property Insurance multiplied by the Transmission Plant Allocation Factor, and (3) Expenses included in Account 928 (excluding Merger-Related Costs included in Account 928) related to FERC Assessments multiplied by Plant Allocation Factor, plus any other Federal and State transmission related expenses or assessments, plus specific transmission related expenses included in Account 930.1 plus Transmission Merger-Related Costs. This sum shall be multiplied by the PTF/HTF Transmission Plant Allocation Factor.

I. Transmission Related Integrated Facilities Charges shall equal the PTO's transmission payments to Affiliates for use of the PTF and HTF integrated transmission facilities of those Affiliates.

J. Transmission Support Revenues shall equal the PTO's revenue received for PTF and HTF transmission support but excluding the support payments to PTOs or their designee pursuant to Schedule 11 and excluding the support payments to PTOs or their designee pursuant to Schedule 12 Part 1(a) and Part B.2, and excluding support payments, if any, made to PTOs or their respective designee pursuant to Part II.C of this OATT.

K. Transmission Support Expense shall equal the expense paid by (1) PTOs, (2) Transmission Customers or (3) Related Persons pursuant to Section II.49 of the Tariff for PTF and HTF transmission support other than expenses for payments made for congestion rights or for transmission facilities or facility upgrades placed in service on or after January 1, 1997, where the support obligation is required to be borne by particular PTOs or other entities in accordance with the OATT. Transmission Support Expenses by any entity other than a PTO, included in this provision, shall be capped at that entity's annual payment for Regional Network Service or its Point To Point Service for each individual Point To Point transaction from the resource with which the support payment is associated.

L. <u>Transmission-Related Expense from Generators</u> shall equal the expenses from generators that both (1) the PTO Administrative Committee determines should be included as transmission expense as a result of the impact of such generators on reducing transmission costs that would otherwise be required to be paid by Transmission Customers and (2) are reflected in a filing made by the PTOs with the Commission under Section 205 of the Federal Power Act and accepted by the Commission for recovery under the OATT.

M. <u>Transmission Related Taxes and Fees Charge</u> shall include any fee or assessment imposed by any governmental authority on service provided under this Section which is not specifically identified under any other section of this rule.

N. <u>Revenues for Short-Term service under the OATT</u> shall be revenues distributed to each PTO for short term service provided under the OATT, received after March 1, 1999. These revenues will be credited pro-rata between pre-1997 and post-1996 PTF revenue requirements in proportion to pre-1997 and post-1996 PTF Transmission Plant.

O. <u>Transmission Rents Received from Electric Property</u> shall equal any Account 454 Rents from electric property, associated with PTF and HTF Transmission Plant as defined in Section II.A.1.(a) above but not reflected as a credit in Transmission Support Revenues in paragraph K of this Attachment.

P. <u>Transmission Revenues from MGTSAs</u> shall equal any MGTSA revenues recorded in Account 456.

APPENDIX A TO ATTACHMENT F

IMPLEMENTATION RULE RULES FOR DETERMINING

INVESTMENT TO BE INCLUDED IN PTF

Section A – Transmission Lines*

Section B – Terminal Facilities*

Section C – Right of Way*

Effective June 1, 1998

*The following provision shall apply to Sections A, B and C below:

Of those transmission facilities that are upgrades, modifications or additions to the New England Transmission System on and after January 1, 2004, only those that: (i) are rated 115kV or above, and (ii) otherwise meet the non-voltage criteria specified in Section II.49 of this OATT shall be classified as PTF. Those transmission facilities that were PTF on December 31, 2003, and any upgrades to such facilities that meet the definition of PTF specified in this OATT, shall remain classified as PTF for all purposes under the Transmission, Markets and Services Tariff.

Section A: Rules for Determining Transmission Line Investment to be Included in PTF

Pool Transmission Facilities (PTF) are the transmission facilities owned by PTO rated 69 kV or above required to allow energy from significant power sources to move freely on the New England transmission network, and include:

1. All transmission lines and associated facilities owned by the PTOs rated 69 kV and above, except:

    a. those which are required to serve local load only, thereby contributing little or no parallel capability to the transmission network,

    b. generator leads, which are defined as the radial transmission from a generator bus to the nearest point on the transmission network,

c. lines that are normally operated open.

d. those that are classified as MTF.

2. Terminal facilities (including substation facilities such as transformers, circuit breakers, and associated equipment) required to interconnect the lines which constitute PTF (see Section B).
3. If a PTO with significant generation in its system (initially 25 MW) is connected to the New England Transmission System and none of the transmission facilities owned by the PTO qualify to be included in PTF as defined in “1” and “2” above, then such PTO’s connection to PTF will constitute PTF if both of the following requirements are met for this connection:

   a. The connection is rated 69 kV or above.

   b. The connection is the principal transmission link between the PTO and the remainder of the ISO PTF network.

The PTF facilities covered by this provision shall consist of a single line from the point of connection on the transmission network to the first bus within the PTO’s system.

4. R/W and land required for the installation of PTF facilities listed in “1”, “2”, or “3” (see Section C).

The following examples indicate the intent of the above definitions:

a. Radial tap lines to local load are excluded.

b. Lines which loop, from two geographically separate points on the transmission network, the supply to the load bus from the transmission network are included.

c. Lines which loop, from two geographically separate points on the transmission network, the connections between a generator bus, and the transmission network are included.

d. Radial connection or connections from a generating station to a single substation or switching station on the transmission network are excluded unless the requirements of paragraph 3 above are met.

e. The cost of a PTF line will include only those costs associated with that line. When other facilities require rebuilding or undergrounding to permit the construction of a PTF facility, the investment costs in the relocated or undergrounded facility will not be included.

f. Where multiple circuit structures support a mixture of PTF and Non-PTF circuits, the total cost of the multiple circuit structures will be allocated between the circuits in accordance with the ratio of costs of comparable individual structures.

The PTOs shall review at least annually the status of transmission lines and related facilities and determine whether such facilities constitute PTF and shall prepare and keep current a schedule or catalog of PTF facilities.

All new facilities being installed should be properly classified at the time the facilities are approved under Section I.3.9 of the Transmission, Markets and Services Tariff.

Transmission facilities owned or supported by a Related Person of a PTO which are rated 69 kV or above and are required to allow Energy from significant power sources to move freely on the New England Transmission System shall also constitute PTF provided (i) such Related Person files with the ISO its consent to such treatment; and (ii) the ISO determines in consultation with the PTO Administrative Committee determines that treatment of the facility as PTF will facilitate accomplishment of the ISO’s objectives. If such facilities constitute PTF pursuant to this paragraph, they shall be treated as “owned” or “supported,” as applicable, by a PTO for purposes of the OATT and the other provisions of the TOA, including the ability to include the cost associated with such PTF and any Transmission Support Expenses for support of PTF made by its Related Person in that PTO’s Annual Transmission Revenue Requirements pursuant to Attachment F of the OATT.

Section B: Rules for Determining Terminal Investment to be Included in PTF

Terminal Investment is investment associated with the terminal facilities of electrical lines, including substation facilities such as transformers, circuit breakers, disconnects and airbreaks, bus conductor, related protection equipment and other related facilities (see paragraph 7).

1. The investment in terminal facilities shall be included where these facilities are identifiable and serve directly for terminating and/or switching PTF lines.

2. In cases where a line terminal is used in conjunction with both PTF and Non-PTF lines and/or facilities, it will be considered a PTF facility providing the terminal facility is at 69 kV or above and carries any power flow at 69 kV or above through parallel paths within the interconnected network under normal operation. PTF equipment is any element of the transmission system in those parallel paths. Any equipment not in these parallel paths is Non-PTF.

3. Where line terminals are installed solely for Non-PTF facilities, and do not carry any power flow at 69 kV or above through parallel paths within the interconnected network under normal operation, such terminal cost shall not be included in PTF.

4. A two-winding transformer which connects PTF facilities at both terminals along with any switcher which can be identified as pertaining solely to the transformer, will be included in their entirety as PTF.

5. An autotransformer or three winding transformer which connects PTF facilities at two (2) or more terminals, along with any switchgear which can be identified as pertaining solely to the PTF-connected terminals of the transformer, will be included in their entirety as PTF. An autotransformer or three winding transformer which is connected to PTF at only one terminal will not be PTF.

6. When a transformer supplies only Non-PTF facilities, the entire transformer installation, including the high side disconnect switch or circuit breaker and associated structures or tap lines shall be excluded from PTF except for the portion of line terminal facilities covered by paragraph 2.

7. Other facilities – the investment in that portion of a multi-use substation or switching station which is identifiable as serving a PTF function shall be included in PTF, while the investment in

such facilities which are identifiable as serving a Non-PTF function shall be excluded. The investment in land, structures, ground mats, fences, ducts, lighting, etc., can often be identified and thus allocated. The investment in other facilities in the substation or switching station, excluding transformers, which are not identifiable as serving either a PTF or a Non-PTF function and general overheads shall be allocated to PTF on the basis of the ratio of the investment in those facilities identified as PTF to the sum of the investments in the facilities which are identified as serving PTF and Non-PTF functions; the equipment cost of power transformers shall not be included in this calculation for determining the division of investment, since this would produce a distorted balance.

8. Alternate method of allocating the cost of terminal facilities – In those cases where the major portion of the investment has been lumped and utility plant records do not permit the accurate assignment of costs to specific terminals, the total investment may be prorated to PTF and Non-PTF according to the number of terminals serving PTF and Non-PTF facilities.

9. In cases where microwave facilities are used in whole or part for PTF purposes, a prorated portion of such investment shall be included in PTF based on the PTF and Non-PTF functions served by the microwave facilities except where these facilities are otherwise supported under the Microwave Sharing Agreement dated June 1, 1970 among some of the New England utilities.

10. Generator unit transformers and generator circuit breakers shall be excluded from PTF, unless otherwise included by paragraphs 1 or 5.

11. In cases where remote control (Supervisory Control) and telemetering facilities are used in whole or in part for PTF purposes, a prorated portion of such investment shall be included in PTF based on the PTF and Non-PTF functions served by these facilities.

12. The PTO Administrative Committee may designate appropriate facilities as PTF.

Section C: Rules for Determining PTF R/W Costs

1. If a R/W has only PTF lines and no Non-PTF lines are expected to be added, the entire cost of the R/W is to be included as PTF.

2. If the R/W has only PTF lines but includes additional unused R/W which was purchased for future use by Non-PTF lines, the cost of the additional R/W is not to be included as PTF.

3. If the R/W contains both PTF and Non-PTF lines, the R/W cost to be assigned to PTF is to be determined as follows:

    a. Where new or additional R/W is required to permit the construction of PTF line(s) and the added R/W is adequate to contain the new PTF, the cost of the new R/W is to be assigned to the PTF line(s), (even if the PTF line is located on the old R/W).

    b. Where an existing R/W is used (without additional R/W), the amount allocated to PTF will be determined in accordance with paragraph 4.

    c. Where a R/W is widened, but the new facilities, either PTF or Non-PTF, require partial use of the existing R/W, the incremental cost of the new R/W will be assigned to the new facilities. The width of the original R/W will be added to the width of the new R/W and the combined width will be allocated between PTF and Non-PTF as in paragraph 4. The cost of the old R/W and the combined width will be allocated between PTF and Non-PTF as in paragraph 4. The cost of the old R/W will be allocated to the new facilities in proportion to the width of the old R/W assigned to the new facilities. Thus, the R/W for the new facilities will be the additional R/W plus a share of the old R/W.

4. In allocating R/W between PTF and Non-PTF lines, each shall bear a share of the R/W in accordance with the following formulae.

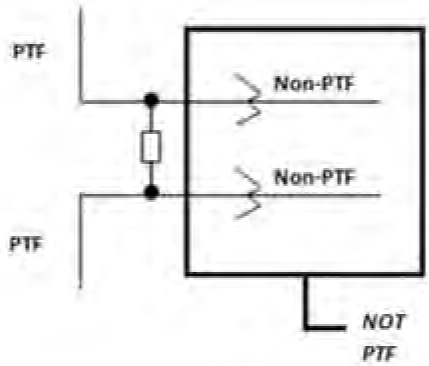
    a. Determine the R/W width required for each facility if constructed independently using appropriate type structures.

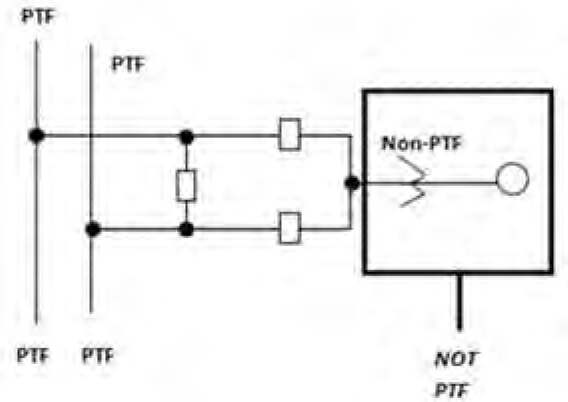
    b. Allocate the actual R/W width to each facility in the proportion its independent R/W requirement would be to the sum of the independent R/W requirements.

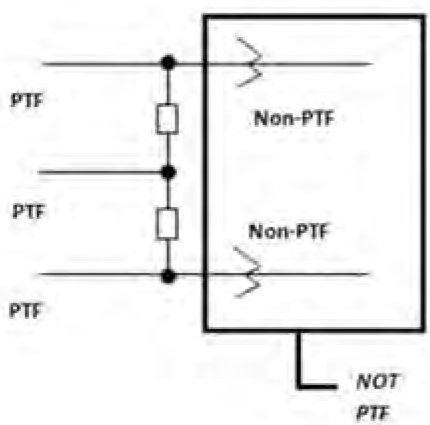
5. R/W and land held for future PTF facilities may be included in PTF facilities only if specifically approved by the PTO Administrative Committee included under paragraph 1.

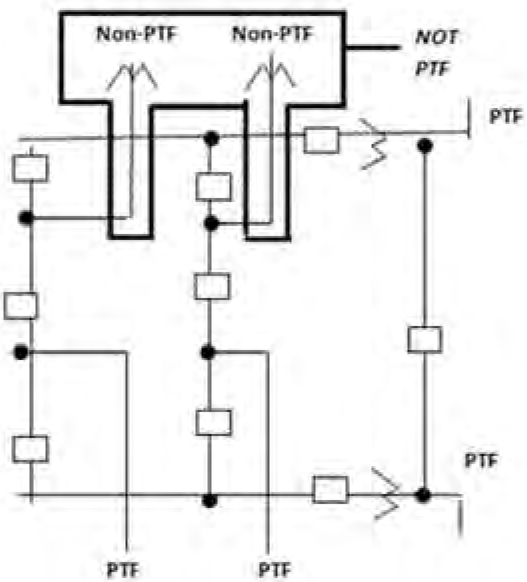
ATTACHMENT 1 TO APPENDIX A TO ATTACHMENT F IMPLEMENTATION RULE

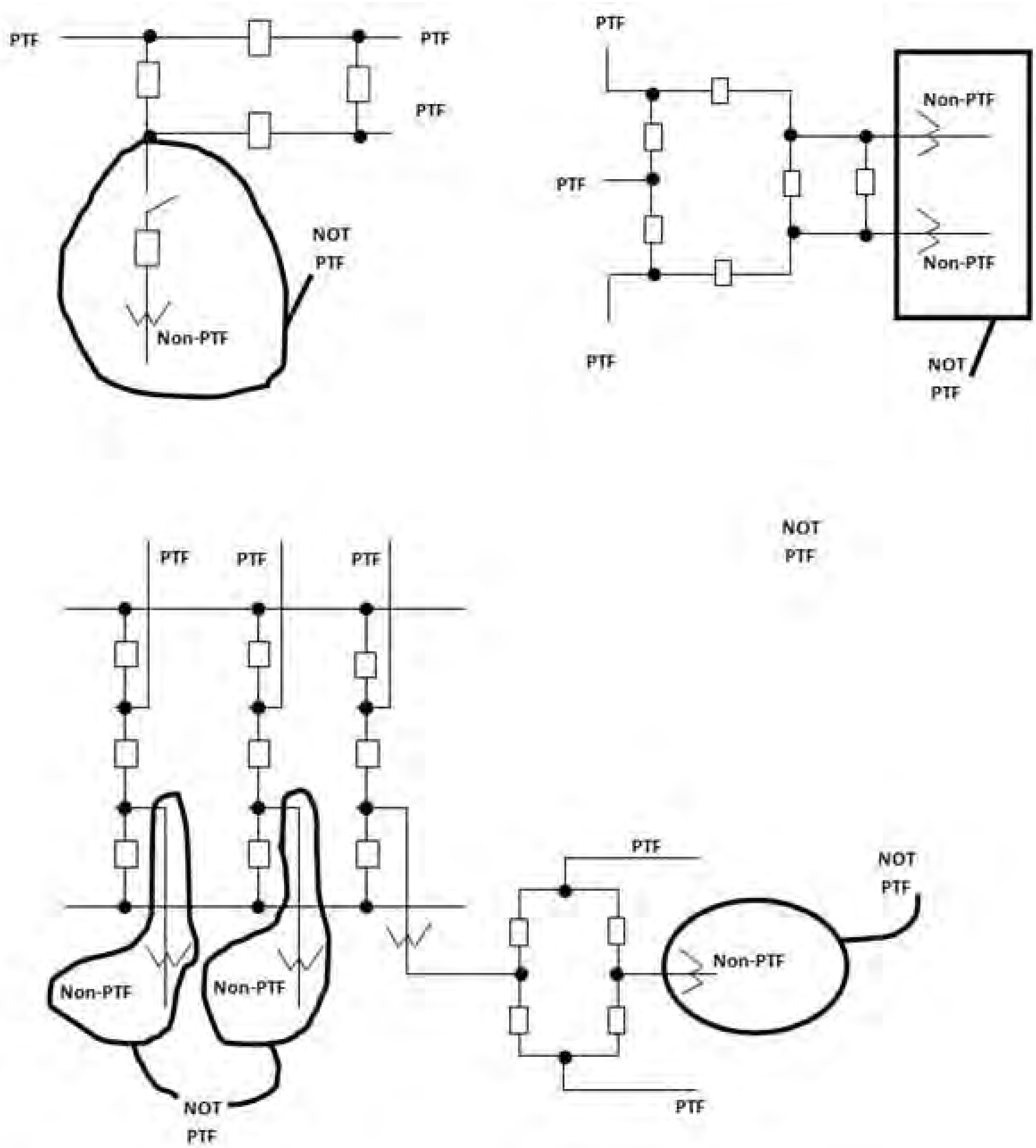
Examples of the Methods for Distinguishing PTF from Non-PTF Terminal Facilities in a Number of Typical Substation Configurations











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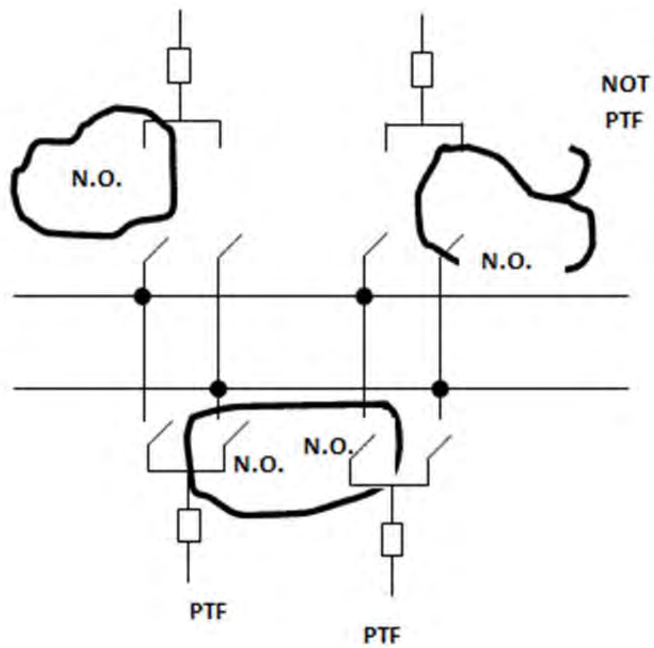
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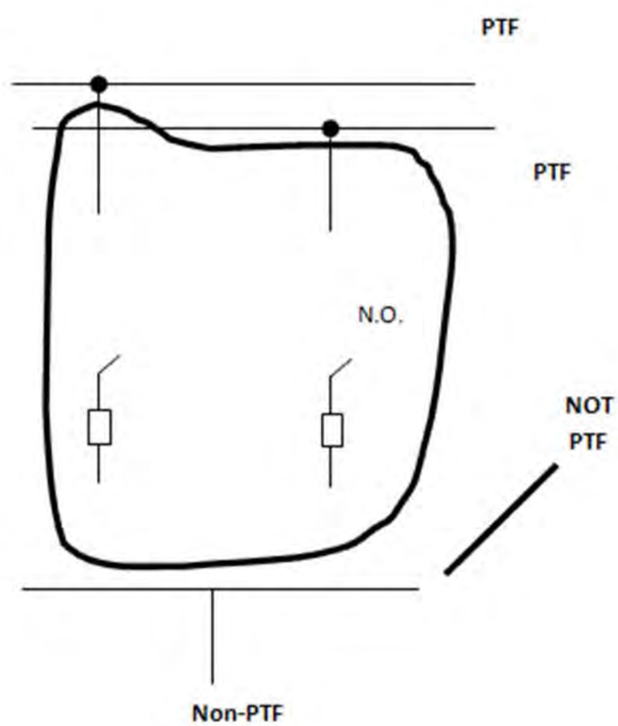
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APPENDIX B TO ATTACHMENT F IMPLEMENTATION RULE
HTF TRANSITION SCHEDULE

The inclusion of HTF Annual Transmission Revenue Requirements in Attachment F (and the calculation of the Pool PTF Rate) to this OATT will be limited by the provisions of this schedule.

VELCO, as a PTO and acting as agent for the HTF owners, may include the HTF Annual Transmission revenue Requirements (i.e., HTF Transmission Plant) within the Attachment F calculations. Additionally, the total HTF Annual Transmission Revenue Requirements included shall be limited to the following:

Year 1: A maximum of $1.2M in Year 1. For the sole purpose of this Schedule, “Year 1” shall be defined as the first full year after the Operations Date:

Year 2: A maximum of $2.0M in Year 2. For the sole purpose of this Schedule, “Year 2” shall be defined as the second full year after the Operations Date;

Year 3: A maximum of $2.8M in Year 3. For the sole purpose of this Schedule, “Year 3” shall be defined as the third full year after the Operations Date;

Year 4: A maximum of $3.5M in Year 4. For the sole purpose of this Schedule, “Year 4” shall be defined as the fourth full year after the Operations Date;

and

Year 5 and thereafter: All HTF Annual Transmission Revenue Requirements shall be included in Attachment F.

ATTACHMENT F IMPLEMENTATION RULE
APPENDIX C

I. DEFINITIONS

(i) **Annual True-up – Pre-1997 (ATU):** shall be the difference between the actual Pre-1997 Annual Transmission Revenue Requirements and the as-billed Pre-1997 Annual Transmission Revenue Requirements, adjusted to include interest pursuant to Part II below. The actual Pre-1997 Annual Transmission Revenue Requirements shall be an after-the-fact calculation and shall be determined at the conclusion of each rate-effective period, i.e. June 1 through May 31 of each year, by application of the Attachment F formula rate and each PTO’s relevant Pre-1997 PTF cost data for the most recently concluded calendar year. The as-billed Pre-1997 Annual Transmission Revenue Requirements shall be those Pre-1997 Annual Transmission Revenue Requirements used to establish the RNS rates that were made effective on June 1 of the most recently concluded calendar year.

(ii) **Annual True-up – Post-1996 (ATU’):** shall be the difference between the actual Post-1996 Annual Transmission Revenue Requirements and the as-billed Post-1996 Annual Transmission Revenue Requirements, adjusted to include interest pursuant to Part II below. The actual Post-1996 Annual Transmission Revenue Requirements shall be an after-the-fact calculation and shall be determined at the conclusion of each rate-effective period, i.e. June 1 through May 31 of each year, by application of the Attachment F formula rate and each PTO's relevant Post-1996 PTF cost data for the most recently concluded calendar year.The as-billed Post-1996 Annual Transmission Revenue Requirements shall be those Post-1996 Annual Transmission Revenue Requirements used to establish the RNS rates that were made effective on June 1 of the most recently concluded calendar year and which included the sum of the Post-1996 Transmission Revenue Requirements for the year prior to the most recently concluded calendar year plus the Forecasted Transmission Revenue Requirements for the most recently concluded calendar year.

(iii) Forecast Period: The calendar year immediately following the calendar year for which the most recent FERC Form 1 data is available.

(iv) Forecasted Transmission Plant Additions (FTPA): shall equal an estimate of the PTO's Post-1996 PTF plant additions for the Forecast Period.

(v) Forecasted MPRP CWIP (FCWIP): shall equal CMP's estimated incremental change in MPRPCWIP for the Forecast Period.

(vi) Carrying Charge Factor (CCF): shall reflect the most recent calendar year data used in determining Post-1996 Annual Transmission Revenue Requirements and shall equal the sum of Attachment F Sections II.A, excluding MPRP CWIP and NEEWS CWIP, through II.H divided by Attachment F Section II.A.1.a.

(vii) MPRP Cost of Capital Rate (MCOC): shall be determined in accordance with Attachment F Section II.A.2.

(viii) Forecasted Transmission Revenue Requirement (FTRR): shall equal FTPA multiplied by the CCF plus FCWIP multiplied by the MCOC, plus FCCWIP multiplied by CCOC, plus FWCWIP multiplied by WCOC, plus FNCWIP multiplied by NCOC, as shown:

FTRR = FTPA * CCF + (FCWIP * MCOC) + (FCCWIP * CCOC) + (FWCWIP * WCOC) + (FNCWIP * NCOC)

(ix) Forecasted CL&P NEEWS CWIP (FCCWIP): shall equal CL&P’s estimated incremental change in NEEWS CWIP for the Forecast Period.

(x) Forecasted WMECO NEEWS CWIP (FWCWIP): shall equal WMECO’s estimated incremental change in NEEWS CWIP for the Forecast Period.

(xi) NEEWS CL&P Cost of Capital Rate (CCOC): shall be determined in accordance with Attachment F Section II.A.2.

(xii) NEEWS WMECO Cost of Capital Rate (WCOC): shall be determined in accordance with Attachment F Section II.A.2.

(xiii) Forecasted NEP NEEWS CWIP (FNCWIP): shall equal NEP’s estimated incremental change in NEEWS CWIP for the Forecast Period.

(xiv) NEEWS NEP Cost of Capital Rate (NCOC): shall be determined in accordance with Attachment F Section II.A.2.

II. INTEREST ON ANNUAL TRUE-UPS

Interest on the Annual True-up amounts (i.e., interest applicable to any over or under collection) shall be calculated in accordance with the methodology specified in the Commission's regulations at 18 C.F.R. § 35.19a (a) (2) (iii).

III. INFORMATIONAL FILINGS

The PTOs' annual informational filing shall include supporting documentation for their estimated capital additions to be placed in service during the current calendar year as well as supporting documentation pertaining to any annual true-up and interest calculations.

SCHEDULE 1

SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE

Scheduling, System Control and Dispatch Service is the service required to schedule at the regional level the movement of power through, out of, within, or into the New England Control Area. Local level service is provided by the PTOs under Schedule 21 to this OATT. For transmission service under this OATT, this Ancillary Service can be provided only by the ISO and the Transmission Customer must purchase this service from the ISO. Charges for Scheduling, System Control and Dispatch Service are to be based on the expenses incurred by the ISO, and by the individual PTOs in the operation of Local Control Center dispatch centers or otherwise, to provide these services. The expenses incurred by the ISO in providing these services recovered under Section IV of the OATT. A surcharge for the expenses incurred by PTOs in the provision of these services for transmission service over the PTF will be added to the Through or Out Service rate and to the Regional Network Service rate. Any Scheduling, System Control and Dispatch Service expenses for the provisions of these services for MTF Service shall be determined separately and assessed to Transmission Customers receiving MTF Service, in accordance with the arrangements between the Transmission Customers receiving MTF Service and the MTF Provider.

The expenses incurred in providing Scheduling, System Control and Dispatch Service for transmission service over the PTF for each PTO will be determined by an annual calculation based on the previous calendar year's data as shown, in the case of PTOs which are subject to the Commission's jurisdiction, in the PTO's FERC Form 1 report for that year, and shall be based on actual data in lieu of allocated data if specifically identified in the Form 1 report. The surcharge shall be redetermined annually as of June 1 in each year and shall be in effect for the succeeding twelve (12) months. The rate surcharge per kilowatt for each month is one-twelfth of the amount derived by dividing the total annual PTO expenses for providing the service by the sum of the average of the coincident Monthly Peaks (as defined in Section II.21.2) of all Local Networks for the prior calendar year.

Each Transmission Customer which is obligated to pay the rate for Regional Network Service for a month shall pay the surcharge on the basis of the number of kilowatts of its Monthly Network Load (as defined in Section II.21.2 of this OATT) for the month. Each Transmission Customer which is obligated to pay the rate for Through or Out Service for the applicable period shall pay the surcharge on the basis of the highest amount of its Reserved Capacity for each transaction scheduled as Through or Out Service for such period.

The details for implementation of Schedule 1 for transmission service over the PTF shall be established in accordance with the Implementation Rule for Schedule 1 attached to this OATT.

SCHEDULE 1 IMPLEMENTATION RULE

This rule provides detail with respect to the calculation of the rate surcharge each year for Scheduling, System Control and Dispatch Service, which is defined in the OATT as the service required to schedule the movement of power through, out of, within, or into the New England Control Area over Pool Transmission Facilities ("PTF"). This service also includes the dispatch and security analysis of the system. Scheduling, System Control and Dispatch Service for transmission service over transmission facilities other than PTF is provided under Schedule 21 of the OATT. For transmission service under the OATT, this Ancillary Service will be provided by the ISO, and rates collected under Schedule 1 are based on expenses incurred by the Local Control Centers, and the PTOs (as described herein) in providing the necessary elements of this service to the ISO. All of the costs of the ISO for the provision of service under Schedule 1 will be recovered under Section IV of the Transmission, Markets and Services Tariff. Schedule 1 of the OATT is for collection only of the revenue requirements for Local Control Centers and PTOs for System Control and Dispatch Service. Any Transmission Customer taking Regional Network Service or Through or Out Service shall be subject to the rate surcharge calculated under Schedule 1 of the OATT as described in more detail in this rule below.

The PTOs shall make an annual informational filing on or before July 31 of each year showing the Schedule 1 rate surcharge to be utilized by the ISO in the billing of Schedule 1 Ancillary Service that will be in effect for the period beginning June 1 of that year through May 31 of the subsequent year. If there are any corrections made to the information reflected in the informational filing after it has been submitted, the PTOs would file corrections to the informational filing. At least thirty (30) days before the informational filing is made with the Commission, the PTOs shall make available to Transmission Customers and any other interested parties a draft of the proposed filing for review and comment prior to the filing by posting such draft on the RTO NE website. The filing of the informational filing does not reopen the formula rate set forth below for review, but rather is contestable only with respect to the accuracy of the information contained in the informational filing. The ISO shall have the discretion to conduct audits of such charges, with advisory Stakeholder input on the scope of audit, including on any agreed-upon procedures to be used by the auditor. In this provision, the term "agreed-upon procedures" shall have the meaning afforded to it by the American Institute of Certified Public Accountants.

I. DEFINITIONS

Capitalized terms used in this rule that are not defined in the Tariff have the following definitions:

Scheduling and Dispatch Surcharge Rate shall equal the rate surcharge that is determined for the applicable period beginning on June 1, 1999, in accordance with Section II of this rule below.

PTF Transmission-Related Local Control Center Scheduling and Dispatch Expense shall equal the PTF transmission related expenses incurred by the PTO from REMVEC II, CONVEX/ESCC, and the Maine Local Control Center as recorded in each PTO's FERC Form 1, Account Nos. 561-561.4, excluding any charges recorded in this account that were incurred under the OATT or Schedule 21 of the OATT. The expenses shall be net of any revenues, as reflected in FERC Account No. 456, received by the PTO for providing scheduling and dispatch services, excluding any revenues recorded in this account that where received as a result of charges under the OATT.

REMVEC II is a Local Control Center of the ISO providing security analysis of PTF.

Local PTF Transmission-Related Scheduling and Dispatch Expense shall equal the sum of (1) each PTO's expenses as recorded in FERC Account Nos. 561-561.4, excluding any ISO and Local Control Center related expenses and any expenses recorded in these accounts, that were incurred under this OATT or the Schedule 21 of this OATT of each PTO as a Transmission Customer, multiplied by the PTF Transmission Plant Allocator, (2) NSTAR Electric Company SCADA-related expenses as calculated in accordance with Appendix A of this Rule, (3) the Central Maine Power Company Local Control Center revenue requirements as calculated in accordance with Appendix B of this Rule, and (4) the CL&P Dispatch Center Revenue Requirement as calculated in accordance with Appendix C of the Rule.

PTF Transmission Plant Allocation Factor is the factor for allocating transmission costs and expenses between PTF and Non-PTF as determined for the applicable period pursuant to Attachment F of the OATT.

II. CALCULATION OF THE SCHEDULING AND DISPATCH SURCHARGE

A. Surcharge for Regional Network Service Customers

For Network Customers, the scheduling and dispatch surcharge for Regional Network Service shall equal the Network Customer's Regional Monthly Network Load, as defined in Section II.21.2 of the OATT,

multiplied by the Monthly Scheduling and Dispatch Surcharge Rate as determined in accordance with Section II.C below.

B. Surcharge for Through or Out Customers

For Through or Out Service Customers, the Scheduling and Dispatch Surcharge shall equal the Transmission Customer's Reserved Capacity for each transaction scheduled for the month multiplied by the applicable Monthly or Hourly Scheduling and Dispatch Surcharge Rate, as determined in accordance with Section II.C below.

C. Scheduling and Dispatch Surcharge Rate

The Scheduling and Dispatch Surcharge Rate will be the surcharge rate in effect from time to time for the applicable period, determined pursuant to the formula described below based on the prior calendar year's data. The Scheduling and Dispatch Surcharge Rate shall be redetermined each year, with the new Surcharge Rate going into effect on June 1 of each year, and be effective for the succeeding twelve months.

In the case of PTOs which are subject to the Commission's jurisdiction, the data used shall be as identified in the PTO's FERC Form 1 report for that year, and shall be based on actual data in lieu of allocated data if specifically identified in the FERC Form 1. When FERC Form 1 data is not the direct source of the data used in the formula, the worksheets used to develop the inputs will reflect Appendix A, Appendix B, and Appendix C of this Rule.

The Scheduling and Dispatch Surcharge Rate shall be equal to the sum of (1) PTF Transmission-Related Local Control Center Scheduling and Dispatch Expense, (2) Local PTF Transmission Related Scheduling and Dispatch Expense, (3) less Schedule 1 revenues from the prior year surcharges for Short-Term Point-To-Point Transactions, and divided by the annual average of the sum of all Regional Network Customers Monthly Peak Load, as defined in Section II.21.2 of the OATT, from the prior calendar year plus the Long-Term Firm Point-To-Point Service Reserved Capacity, from the prior calendar year.

The Monthly Scheduling and Dispatch Surcharge Rate shall equal one-twelfth of the Scheduling and Dispatch Surcharge Rate.

The Hourly Scheduling and Dispatch Surcharge Rate shall be the annual rate divided by 8760.

APPENDIX A TO SCHEDULE 1 IMPLEMENTATION RULE

NSTAR ELECTRIC COMPANY SCADA

This service is required to schedule the movement of power through, out of, within, or into the New England Control Area over Pool Transmission Facilities (PTF). Service under this schedule represents the contribution to that service provided by the PTO's own Dispatch Center, commonly referred to as SCADA. These costs are excluded from costs in Attachment F.

The PTF Revenue Requirement for the scheduling, system control and dispatch service that is based on data for the calendar year 2004 or later shall include an allocated PTF-related amount of Incremental Return and Associated Income Taxes on SCADA-related transmission plant investments included in the Regional System Plan and placed in-service on or after January 1, 2004 (such investments referred to herein as "Post-2003 Dispatch Center Investment"). The Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment shall reflect a surcharge of a 100 basis point ROE adder applicable to certain investment base components as specified in the formula below. The data used in determining the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment shall be based on actual data in lieu of allocated data if specifically identified in NSTAR Electric's accounting records.

Definitions: Dispatch Center Wages and Salaries Allocation Factor: Ratio of Dispatch Center Related Direct Wages and Salaries to NSTAR Electric's total Direct Wages and Salaries excluding Administrative and General Wages and Salaries.

Dispatch Center Plant Allocation Factor: Ratio of Total Investment in Dispatch Center Plant plus Dispatch Center Related General Plant, to Total Plant in service.

Dispatch Center Transmission Plant Allocation Factor: Ratio of Total Investment in Dispatch Center Plant plus Dispatch Center Related General Plant, to Total Investment in Transmission Plant.

The PTF Revenue Requirement for the Scheduling System Control and Dispatch Service shall equal the sum of the PTO's: (A) Return and Associated Income Taxes (including the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment), (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Related Amortization of Investment Tax Credits, (D) Dispatch Center

Related Municipal Tax Expense, (E) Dispatch Center Related Payroll Tax Expense (F) Dispatch Center Operation and Maintenance Expense, and (G) Dispatch Center Related Administrative and General Expense; multiplied by the PTF Transmission Plant Allocation Factor.

The Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment shall be calculated using the Dispatch Center investment base components specifically identified in Section A.1 of the formula below.

A. <u>Return and Associated Income Taxes</u> shall equal the product of the Dispatch Center Investment Base and the Cost of Capital Rate. To calculate the Incremental Return and Associated Income Taxes for Post–2003 Dispatch Center Investment, the Dispatch Center Investment Base will only include items (a), (d) and (e) under Section (A)(1), calculated in the manner indicated.

1. **<u>The Dispatch Center Investment Base</u>** will consist of (a) Dispatch Center Plant in FERC accounts 350-359, plus (b) Dispatch Center Related General Plant, plus (c) Dispatch Center Plant Held for Future Use, less (d) Dispatch Center Related Depreciation Reserve, less (e) Dispatch Center Related Accumulated Deferred Taxes, plus (f) Other Regulatory Assets, plus (g) Dispatch Center Prepayments, plus (h) Dispatch Center Materials and Supplies, plus (i) Dispatch Center Related Cash Working Capital.

a. <u>Dispatch Center Plant</u> will equal the year-end balance of the PTO's Investment in Dispatch Center per FERC accounts 350 through 359. Dispatch Center Plant Investment is not included in PTF investment in the Attachment F revenue requirement. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, Post-2003 Dispatch Center Plant shall be separately identified.

b. <u>Dispatch Center Related General Plant</u> shall equal the PTO's year-end balance of Investment in General Plant multiplied by the Dispatch Center Wages and Salaries Allocation Factor described above.

c. <u>Dispatch Center Plant Held for Future Use</u> shall equal the year-end balance of Transmission related Dispatch Center Investment in FERC account 105.

d. <u>Dispatch Center Related Depreciation Reserve</u> shall equal the year-end balance of Transmission Dispatch Center Depreciation Reserve, plus the year-end balance of

Dispatch Center Related General Depreciation Reserve. Dispatch Center Related General Plant Depreciation Reserve shall equal the product of General Plant Depreciation Reserve and the Dispatch Center Wages and Salaries Allocation Factor described above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, Dispatch Center Depreciation Reserve associated with the Post-2003 Dispatch Center Investment, shall equal the balance of the Dispatch Center Depreciation Reserve multiplied by the ratio of Post-2003 Dispatch Center Plant to total investment in Dispatch Center Plant.

e. Dispatch Center Related Accumulated Deferred Taxes shall equal the year-end balance of Total Accumulated Deferred Income Taxes, multiplied by the Dispatch Center Plant Allocation Factor described above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, Total Accumulated Deferred Income Taxes associated with the Post-2003 Dispatch Center Investment, shall equal the balance of total property-related accumulated deferred income taxes as recorded in FERC Accounts 281 and 282, multiplied by the Dispatch Center Plant Allocation Factor, further multiplied by the ratio of the Post-2003 Dispatch Center Plant to total investment in Dispatch Center Plant.

f. Other Regulatory Assets shall equal the year-end balance of FAS 106 multiplied by the Dispatch Center Wages and Salaries Allocation Factor described in Section (A) (2) (b) above and the year-end balance of FAS 109, net of FAS 109 liability, multiplied by the Dispatch Center Plant Allocation Factor described in above.

g. Dispatch Center Prepayments shall equal the year-end balance of Prepayments multiplied by the Dispatch Center Wages and Salaries Allocation Factor described above.

h. Dispatch Center Materials and Supplies shall equal the year-end balance of Transmission Plant Materials and Supplies multiplied times the Dispatch Center Plant Allocation Factor described above.

i. Dispatch Center Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Dispatch Center Transmission Related Operation and Maintenance Expense and Dispatch Center Transmission Related Administrative and General Expense.

2. The Cost of Capital Rate shall equal (a) the Weighted Cost of Capital, plus (b) Federal Income Taxes, plus (c) State Income Taxes.

a. the Weighted Cost of Capital will be calculated based upon the PTO's capital structure at the end of each year and will equal the sum of (i), (ii) and (iii) below.

The Cost of Capital Rate to be used in calculating the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, shall only reflect item (iii) below and shall apply in the manner indicated below.

i. the Long Term Debt Component, which equals the product of the actual weighted average embedded cost to maturity of Long Term Debt then outstanding and the ratio that Long-Term Debt is to Total Capital.

ii. the Preferred Stock Component, which equals the product of the actual weighted average embedded cost to maturity of Preferred Stock then outstanding and the ratio that Preferred Stock is to Total Capital.

iii. the Return on Equity Component, which equals the product of the PTO's Return on Equity as set in the PTO's RNS open access rate and the ratio that Common Equity is to Total Capital. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, the incremental return on equity shall be the product of 1.00% and the ratio of Common Equity to Total Capital.

b. Federal Income Taxes shall equal

$$\frac{A + [(C+B)/D]) \times FT}{1 - FT}$$

Where FT is the Federal Income Tax Rate and A is the sum of the Preferred Stock Component and the Return on Equity Component, as determined in Sections A.2.(a)(ii) and (iii) above, B is Dispatch Center Related Amortization of Investment Tax Credits, as determined in Section II.D. below, C is the Equity AFUDC component of Dispatch Center Depreciation Expense, as defined in

Section B., and D is Dispatch Center Investment Base, as determined in A.1., above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, the incremental Federal Income Tax shall equal:

$$(A'*FT)/(1-FT)$$

Where FT is the Federal Income Tax Rate and A' is the incremental return on equity component, as determined in Section A.2.(a)(iii) above.

c. <u>State Income Taxes shall equal</u>

$$\frac{(A + [(C+B)/D] + \text{Federal Income Tax}) \times ST}{1 - ST}$$

Where ST is the State Income Tax Rate and A is the sum of the Preferred Stock Component and the Return on Equity Component, as determined in Section A.2.(a)(ii), and Section A.2.(a)(iii) above, and Federal Income Tax is the rate determined in Section A.2.(b) above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, the incremental State Income Tax shall equal:

$$(A'+ \text{Federal Income Tax})*ST/(1-ST)$$

Where ST is the State Income Tax Rate and A' is the incremental return on equity component, as determined in Section A.2.(a)(iii) above, and Federal Income Tax is the rate determined in Section A.2.(b) above.

B. <u>Dispatch Center Depreciation Expense</u> shall equal the sum of Transmission Depreciation Expense for Dispatch Center Plant, plus an allocation of General Plant Depreciation Expense calculated by multiplying General Plant Depreciation Expense by the Dispatch Center Wages and Salaries Allocation Factor, described in Section (A)(1)(b) above.

C. <u>Dispatch Center Related Amortization of Investment Tax Credits</u> shall equal the PTO's Amortization of Investment Tax Credits multiplied by the Dispatch Center Plant Allocation Factor described above.

D. Dispatch Center Related Municipal Tax Expense shall equal the PTO's total Municipal Tax Expense multiplied by the Dispatch Center Plant Allocation Factor described above.

E. Dispatch Center Related Payroll Tax Expense shall equal the PTO's total electric payroll tax expense, multiplied by the Dispatch Center Wages and Salaries Allocation Factor, described above.

F. Dispatch Center Operation and Maintenance Expense shall equal all expenses related to SCADA operation charged to FERC Account Number 561 through 561.4, excluding any ISO and Local Control Center related expenses and any expenses recorded in this Account that were incurred under this OATT or the Local Service Schedules of this OATT as a Transmission Customer.

G. Dispatch Center Related Administrative and General Expenses shall equal the sum of (1) PTO's Administrative and General Expenses~~, excluding Accounts 924, 928 and 930.1,~~ multiplied by the Dispatch Center Wages and Salaries Allocation Factor, (2) Property Insurance multiplied by the Dispatch Center Plant Allocation Factor, and (3) Expenses included in Account 928 (excluding Merger-Related Costs included in Account 928) related to FERC Assessments multiplied by Dispatch Center Plant Allocation Factor, plus any other Federal and State Dispatch Center related expenses or assessments, plus specific Dispatch Center related expenses included in Account 930.1 plus Transmission Merger-Related Costs multiplied by the Dispatch Center Transmission Plant Allocation Factor.

APPENDIX B TO SCHEDULE 1 IMPLEMENTATION RULE CENTRAL MAINE POWER COMPANY LOCAL CONTROL CENTER

I. DEFINITIONS

Capitalized terms not otherwise defined in the Tariff and as used in this rule have the following definitions:

A. ALLOCATION FACTORS

1. Wages and Salaries Allocation Factor shall equal the ratio of the Local Control Center Direct Wages and Salaries to total direct wages and salaries excluding administrative and general wages and salaries.

2. Local Control Center Wages and Salaries Allocation Factor shall equal the ratio of the Transmission Local Control Center Direct Wages and Salaries to total Local Control Center Direct Wages and Salaries.

3. Local Control Center PTF Allocation Factor shall equal the ratio of the Local Control Center PTF Direct Wages and Salaries to the total Local Control Center Transmission Direct Wages and Salaries.

4. Local Control Center Plant Allocation Factor shall equal the ratio of the Total Investment in Local Control Center Plant to Total Plant in service.

B. TERMS

Administrative and General Expense shall equal the PTO’s expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928, and 930.1.

Amortization of Investment Tax Credits shall equal the PTO’s credits as recorded in FERC Account No. 411.4

Amortization of Loss on Reacquired Debt shall equal the PTO’s expenses as recorded in FERC Account No. 428.1

Other Regulatory Assets/Liabilities -FAS 106 shall equal the net of the PTO's FAS 106 balance as recorded in FERC Account 182.3 and any FAS 106 balance as recorded in the PTO's FERC Account No. 254.

Other Regulatory Assets/Liabilities -FAS 109 shall equal the net of the PTO's FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in the PTO's FERC Account No. 254.

Payroll Taxes shall equal those payroll expenses as recorded in the PTO's FERC Account Nos. 408.1 and 409.1.

Plant Held for Future Use shall equal the PTO's balance in FERC Account No. 105.

Prepayments shall equal the PTO's prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal the PTO's expenses as recorded in FERC Account No. 924.

PTF Local Control Center Direct Wages and Salaries shall equal the PTO's direct wages and salaries related to providing PTF Local Control Center services as recorded in FERC Account No. 561.

Local Control Center Direct Wages and Salaries shall equal the PTO's direct wages and salaries related to providing Local Control Center services as recorded in FERC Account Nos. 556, 561-561.4, and 581.

Local Control Center Operation and Maintenance Expense shall equal the PTO's expenses recorded in FERC Account Nos. 556, 561-561.4, & 581, less any costs included in FERC Account Nos. 561-561.4 that are otherwise recoverable pursuant to Subpart (1) of the Local PTF Transmission Related Scheduling and Dispatch Expense of the rule implementing the Schedule 1 rate surcharge of the OATT.

Local Control Center Plant Depreciation Reserve shall equal the PTO's depreciation reserve balance for Local Control Center Related Plant as recorded in FERC Account No. 108.

<u>Materials and Supplies</u> shall equal the PTO's balance as recorded in FERC Account No. 154.

<u>Local Control Center Related Depreciation Expense</u> shall equal the PTO's depreciation expense for Local Control Center Related Plant as recorded in FERC Account No. 403.

<u>Local Control Center Related Plant</u> shall equal the PTO's gross plant balances used for system control and dispatch purposes as recorded in FERC Account Nos. 303-399. To the extent that such plant includes any amounts recorded as transmission investment in FERC Account Nos. 350-359, such amounts will be excluded for purposes of determining annual transmission revenue requirements pursuant to the billing rule which implements Attachment F of the OATT.

<u>Local Control Center Support Revenues</u> shall equal the revenues received from Local Control Center supporters as recorded in FERC Account Nos. 454 and 456, excluding any revenues received under Schedule 1 of the OATT or the PTO's Local Service Schedule.

<u>Total Accumulated Deferred Income Taxes</u> shall equal the net of the deferred tax balances as recorded in FERC Account Nos. 281-283 and 190.

<u>Total Loss on Reacquired Debt</u> shall equal the PTO's balance as recorded in FERC Account No. 189.

<u>Total Municipal Tax Expense</u> shall equal the PTO's municipal tax expenses as recorded in FERC Account Nos. 408.1 and 409.1.

<u>Total Plant in Service</u> shall equal the PTO's total gross plant balance as recorded in FERC Account Nos. 301-399.

<u>Transmission Local Control Center Direct Wages and Salaries</u> shall equal the PTO's direct wages and salaries related to providing Local Control Center services as recorded in FERC Account No. 561-561.4.

II. CALCULATION OF TOTAL LOCAL CONTROL CENTER REVENUE REQUIREMENTS

The Local Control Center Revenue Requirements based on data for calendar year 2004 or later shall include an Incremental Return and Associated Income Taxes on Central Maine's local control center investments

included in the Regional System Plan and placed in service on or after January 1, 2004 (such investments referred to herein as "Post-2003 Investment"). The Incremental Return and Associated Income Taxes for Post-2003 Investment shall reflect a surcharge of a 100 basis point ROE adder applicable to certain investment base components as specified in the formula below. The data used in determining the Incremental Return and Associated Income Taxes for Post-2003 Investment shall be based on actual data in lieu of allocated data if specifically identified in Central Maine's accounting records.

The Local Control Center Revenue Requirement shall equal the sum of the Local Control Center related (A) Return and Associated Income Taxes (including the Incremental Return and Associated Income Taxes for Post-2003 Investment), (B) Depreciation Expense, (C) Amortization of Loss on Reacquired Debt, (D) Amortization of Investment Tax Credits, (E) Municipal Tax Expense, (F) Payroll Tax Expense, (G) Operations and Maintenance Expense, (H) Administrative and General, minus (I) Support Revenues.

The Incremental Return and Associated Income Taxes for Post-2003 Investment shall be calculated using the investment base components specifically identified in Section A.1. of the formula below.

A. Return and Associated Income Taxes shall equal the product of the Local Control Center Investment Base and the Cost of Capital Rate reflected in the PTO's Attachment F formula of the OATT. To calculate the Incremental Return and Associated Income Taxes for Post 2003 Investment, Local Control Center Investment Base shall only include Sections II.A.1.(a), (b), and (c), in the manner indicated.

1. Local Control Center Investment Base

The Local Control Center Investment Base will be the year end balances of Local Control Center related: (a) Plant, plus (b) Plant Held for Future Use, less (c) Depreciation Reserve, less (d) Accumulated Deferred Taxes, plus (e) Loss on Reacquired Debt, plus (f) Other Regulatory Assets/Liabilities, plus (g) prepayments, plus (h) Materials and Supplies, plus (i) Cash Working Capital.

(a) Local Control Center Related Plant shall equal the balance of the PTO's Investment in Local Control Center Plant. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Investment, Post 2003 Local Control Center Plant shall be separately identified.

(b) Local Control Center Related Plant Held for Future Use shall equal the balance of Plant Held for Future Use multiplied by the Local Control Center Plant Allocation Factor.

(c) Local Control Center Related Depreciation Reserve shall equal the Depreciation Reserve for the PTO's investment in Local Control Center plant. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Investment, Local Control Center Depreciation Reserve shall equal the Depreciation Reserve for the PTO's Local Control Center Plant identified in (a) above.

(d) Local Control Center Related Accumulated Deferred Taxes shall equal the PTO's electric balance of Accumulated Deferred Income Taxes multiplied by the Local Control Center Plant Allocation Factor. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Investment, Local Control Center Accumulated Deferred Taxes shall equal the PTO's balance of total property related accumulated deferred income taxes recorded in FERC account 281and 282 multiplied by the Local Control Center Plant Allocation Factor and further multiplied by the ratio of Post-2003 Investment to Total Local Control Center Related Plant.

(e) Local Control Center Related Loss on Reacquired Debt shall equal the PTO's electric balance of Total Loss on Reacquired Debt multiplied by the Local Control Center Plant Allocation Factor.

(f) Local Control Center Related Other Regulatory Assets/Liabilities shall equal the PTO's electric balance of any deferred recovery of FAS 106 expenses multiplied by the Local Control Center Wages and Salaries Allocation Factor, plus the PTO's electric balance of FAS 109 multiplied by the Local Control Center Plant Allocation Factor.

(g) Local Control Center Related Prepayments shall equal the PTO's electric balance of prepayments multiplied by the Local Control Center Plant Allocation Factor.

(h) Local Control Center Related Materials and Supplies shall equal the PTO's electric balance of Plant Materials and Supplies, multiplied by the Local Control Center Plant Allocation Factor.

(i) Local Control Center Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Local Control Center Operation and Maintenance Expense, Local Control Center Related Administrative and General Expense.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) the PTO's Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon the capital structure at the end of each year and will equal the sum of (i),(ii), and (iii) below. The Cost of Capital Rate to be used in calculating the Incremental Return and Associated Income Taxes for Post-2003 Investment shall only reflect item (iii) below and shall apply in the manner indicated below

(b) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity of the PTO's long-term debt then outstanding and the ratio that long-term debt is to the PTO's total capital.

(c) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of the PTO's preferred stock then outstanding and the ratio that preferred stock is to the PTO's total capital.

(d) the return on equity component, which equals the product of the PTO's Return on Equity as set in the PTO's RNS open access rate and the ratio that common equity is to the PTO's total capital. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Investment, the incremental return on equity shall be the product of Central Maine's incremental return on equity of 1.0% and the ratio that common equity is to the PTO's total capital.

(e) Federal Income Tax shall equal

$$\frac{(A+[(C+B)/D]) \times FT}{1 - FT}$$

Where FT is the Federal Income Tax Rate and A is the sum of the preferred stock component and the return on equity component, as determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section II.D. below, C is the equity AFUDC component of Local Control Center Depreciation Expense, as defined in II.B., and D is Local Control Center Investment Base, as determined in II.A.1., above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Investment, the incremental Federal Income Tax shall equal

$$\frac{(A' * FT)}{(1 - FT)}$$

where FT is the Federal Income Tax Rate and A' is the incremental return on equity component, as determined in Section II.A.2.(a)(iii) above.

(f) <u>State Income Tax</u> shall equal

$$\frac{(A+[(C+B)/D] + \text{Federal Income Tax}) \times ST}{1 - ST}$$

Where ST is the State Income Tax Rate, A is the sum of the preferred stock component and return on equity component determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section II.D. below, C is the equity AFUDC component of Local Control Center Depreciation Expense, as defined in II.B., D is the Local Control Center Investment Base, as determined in II.A.1., above and Federal Income Tax is the rate determined in Section II.A.1.(b) above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Investment, the incremental State Income Tax shall equal

$$\frac{(A' + \text{Federal Income Tax})(ST)}{(1 - ST)}$$

where ST is the State Income Tax Rate, A' is the incremental return on equity component determined in Section II.A.2.(a)(iii) above, and Federal Income Tax is the rate determined in Section II.A.2.(b) above.

B. <u>Local Control Center Depreciation Expense</u> shall equal the Local Control Center Plant Depreciation Expense and Accumulated Amortization.

C. Local Control Center Related Amortization of Loss on Reacquired Debt shall equal the PTO's electric balance of Loss on Reacquired Debt multiplied by the Local Control Center Plant Allocation Factor.

D. Local Control Center Related Amortization of Investment Tax Credits shall equal the PTO's electric Amortization of Investment Tax Credits multiplied by the Local Control Center Plant Allocation Factor.

E. Local Control Center Related Municipal Tax Expense shall equal the PTO's total electric municipal tax expense multiplied by the Local Control Center Plant Allocation Factor.

F. Local Control Center Related Payroll Tax Expense shall equal the PTO's total electric payroll tax expense, multiplied by the Wages and Salaries Allocation Factor.

G. Local Control Center Operation and Maintenance Expense shall equal the PTO's Operation and Maintenance Expenses recorded in FERC Account Nos. 556, 561-561.4, and 581, less any costs included in FERC Account Nos. 561-561.4 that are otherwise recoverable pursuant to Subpart (1) of Local PTF Transmission Related Scheduling and Dispatch Expense of the rule implementing the Schedule 1 rate surcharge of the OATT.

H. Local Control Center Related Administrative and General Expenses shall equal the sum of (1) PTO's Administrative and General Expenses multiplied by the Wages and Salaries Allocation Factor, (2) Property Insurance multiplied by the Local Control Center Plant Allocation Factor, and (3) Expenses included in Account 928 related to FERC Assessments multiplied by the Local Control Center Plant Allocation Factor, plus any other Federal and State Local Control Center related expenses or assessments, plus specific Local Control Center related expenses included in Account 930.1.

I. Transmission Support Revenues shall equal the PTO's revenue received for providing system control and dispatch service.

III. CALCULATION OF LOCAL CONTROL CENTER TRANSMISSION REVENUE REQUIREMENTS

The Total Local Control Center Revenue Requirements derived in Section II. above are further multiplied by the Local Control Center Wages and Salaries Allocation Factor defined in Section I. A. 2. above to determine the transmission related revenue requirement, and further multiplied by the Local Control Center PTF Allocation Factor defined in Section I. A. 3. above, to determine the PTF Transmission related revenue requirements to be included in Schedule I of the OATT.

APPENDIX C TO SCHEDULE 1 IMPLEMENTATION RULE
CL&P DISPATCH CENTER REVENUE REQUIREMENT

This appendix calculates the CL&P Dispatch Center Revenue Requirement for use in calculating part (4) of the Local PTF Transmission-Related Scheduling and Dispatch expenses in the Schedule 1 Implementation Rule. The CL&P Dispatch Center Revenue Requirement for use during a calendar year shall be based on CL&P's costs for the immediately preceding calendar year.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section II.1 of the OATT and as used in this appendix have the following definitions:

Dispatch Center means CL&P's CONVEX dispatch center.

Dispatch Center Plant shall equal CL&P's year-end gross plant balances used for CL&P's Dispatch Center as recorded in FERC Account Nos. 303, 350-359, and 389-399.

Dispatch Center Depreciation Reserve shall equal CL&P's year-end depreciation reserve balance for Dispatch Center Plant as recorded in FERC Account No. 108. Dispatch Center Accumulated Deferred Income Taxes shall equal the net of CL&P's year-end deferred tax balances for Dispatch center Plant as recorded in FERC Account Nos. 281-283 and 190.

II. CALCULATION OF TOTAL DISPATCH CENTER REVENUE REQUIREMENT

The Dispatch Center Revenue Requirement shall equal the sum of (A) Dispatch Center Return and Associated Income Taxes, (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Amortization of Investment Tax Credits, and (D) Dispatch Center Municipal Tax Expense; provided, that during the period June 1, 2008 through May 31, 2009, the Dispatch Center Revenue Requirement shall equal the product of (i) the number of months (or fractions thereof) remaining in 2007 on and after the date upon which the Convex Agreements are permitted to be made effective by FERC, divided by 12 and (ii) the sum of (A) Dispatch Center Return and Associated Income Taxes, (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Amortization of Investment Tax Credits, and (D) Dispatch Center Municipal Tax Expense. "CONVEX Agreements" refers to the agreements between The Connecticut Light & Power Company and

various entities relating to the operation of the Dispatch Center and filed with FERC contemporaneously with the filing of this Appendix C.

A. Dispatch Center Return and Associated Income Taxes shall equal the product of the Dispatch Center Investment Base and the Cost of Capital Rate.

1. Dispatch Center Investment Base

The Dispatch Center Investment Base will be the year-end balances of:

(a) Dispatch Center Plant, less (b) Dispatch Center Depreciation Reserve, less (c) Dispatch Center Accumulated Deferred Income Taxes.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) the Weighted Cost of Capital, plus (b) Federal Income Tax, plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon CL&P's capital structure at the end of each year and will equal the sum of (i), (ii), and (iii) below.

(i) The long-term debt component, which equals the product of the year-end balance of CL&P's first mortgage bonds and pollution control notes adjusted for premiums, discounts, debt expense and losses on reacquired debt and the ratio of the long term debt to CL&P's total capital.

(ii) The preferred stock component, which equals the product of the year-end balance of CL&P's preferred stock adjusted for premiums, discounts and unamortized issue expense and the ratio of the preferred stock to CL&P's total capital.

(iii) The common equity component, which equals the product of 10.3% and the ratio of the common equity to CL&P's total capital.

(b and c) Federal and State Income Taxes shall be computed as follows:

AxBxC

where: A = Dispatch Center Investment Base

B = Cost of equity capital (the sum of the preferred stock component and common equity component)

C = TC/(1-TE), where TE is the effective combined federal and state statutory income tax rates in effect at the applicable time.

B. Dispatch Center Depreciation Expense shall equal CL&P's Dispatch Center depreciation expense as recorded in FERC Account No. 403.

C. Dispatch Center Amortization of Investment Tax Credits shall equal CL&P's Dispatch Center amortization of investment tax credits as recorded in FERC Account No. 411.1.

D. Dispatch Center Municipal Tax Expense shall equal CL&P's Dispatch Center municipal tax expense as recorded in FERC Account Nos. 408.1 and 409.1.

SCHEDULE 21 - NSTAR

NSTAR ELECTRIC COMPANY

LOCAL SERVICE SCHEDULE

I COMMON SERVICE PROVISIONS

1.0 DEFINITIONS

Whenever used in this Local Service Schedule, in either the singular or plural number, the following capitalized terms shall have the meanings specified in this Section 1. Terms used in this Local Service Schedule that are not defined in this Local Service Schedule shall have the meanings set forth in the Tariff or customarily attributed to such terms by the electric utility industry in New England. Where there is a conflict between this Local Service Schedule and the Tariff, the terms here shall apply.

1.1 Annual Transmission Revenue Requirements

The total annual cost of the Transmission System shall be the amount specified in Attachment D until amended by NSTAR or modified by the Commission.

1.2 Annual True-Up

The reconciliation to actual costs of the estimated costs used for billing purposes under Section 4.0 of this Local Service Schedule for any Service Year.

1.3 Designated Agent

Any entity that performs actions or functions on behalf of NSTAR, an Eligible Customer, or the Transmission Customer required under the Local Service Schedule.

1.4 Firm Local Point-To-Point Service

Transmission service under this Local Service Schedule that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to this Local Service Schedule.

1.5 Load Ratio Share

Ratio of a Transmission Customer’s most recently reported Monthly Network Load in the case of Network Customers and including, where applicable, the Reserved Capacity of Transmission Customers taking Firm Local Point-To-Point Service, to the total load of Network Customers and the Reserved Capacity of Transmission Customers taking Firm Local Point-To-Point Service.

1.6 Local Network

All transmission facilities constituting NSTAR’s non-Pool Transmission Facilities (Non-PTF), excluding the Phase I/II HVDC-TF, which is defined in Schedule 20A of this OATT.

1.7 Local Network Load

The load that a Network Customer designates for Local Network Service under this Local Service Schedule. The Network Customer's Local Network Load shall include all load designated by the Network Customer, (including losses). A Network Customer may elect to designate less than its total load as Local Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete Points of Delivery as Local Network Load, the Eligible Customer is responsible for making separate arrangements under this Local Service Schedule for any Local Point-To-Point Service that may be necessary for such non-designated load.

1.8 Local Network Service

The transmission service provided under this Local Service Schedule over NSTAR's Local Network.

1.9 Local Network Upgrades

Modifications or additions to transmission-related facilities that are integrated with and support NSTAR's overall Transmission System for the general benefit of all users of such Transmission System.

1.10 Local Point-To-Point Service

The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under this Local Service Schedule over NSTAR's Local Network.

1.11 Long-Term Firm Local Point-To-Point Service

Firm Local Point-To-Point Service provided under this Local Service Schedule with a term of one year or more.

1.12 Monthly Network Load

A Network Customer's hourly load (including its designated Local Network Load not physically interconnected with NSTAR under Section 15.2 of this Local Service Schedule) coincident with NSTAR's Monthly Transmission System Peak.

1.13 Native Load Customers

The wholesale and retail power customers of NSTAR on whose behalf NSTAR, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate NSTAR's system to meet the reliable electric needs of such customers.

1.14 NERC

North American Electric Reliability Council, the Electric Reliability Organization of the United States.

1.15 Non-Firm Local Point-To-Point Service

Local Point-To-Point Service under this Local Service Schedule that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in this Local Service Schedule. Non-Firm Local Point-To-Point Service is available on a stand-alone basis for periods ranging from one hour to one month.

1.16 NPCC

Northeast Power Coordinating Council, a regional reliability council of NERC.

1.17 NSTAR

NSTAR Electric Company, a Massachusetts Corporation with offices located at 800 Boylston Street, Boston, Massachusetts 02199. NSTAR owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce and provides service pursuant to the rates, terms and conditions of this Local Service Schedule and the applicable terms and conditions of this Local Service Schedule.

1.18 NSTAR's Monthly Transmission System Load

NSTAR's Monthly Transmission System Peak minus the coincident peak usage of all Firm Local Point-To-Point Service customers pursuant to Part II of this Local Service Schedule plus the Reserved Capacity of all Firm Local Point-To-Point Service customers.

1.19 NSTAR's Monthly Transmission System Peak

The maximum firm usage of NSTAR's Transmission System in a calendar month.

1.20 Parties

NSTAR and the Transmission Customer receiving service under this Local Service Schedule.

1.21 Point(s) of Delivery

Point(s) on NSTAR's Transmission System where capacity and energy transmitted by NSTAR will be made available to the Receiving Party under this Local Service Schedule. The Point(s) of Delivery shall be specified in the Transmission Service Agreement.

1.22 Point(s) of Receipt

Point(s) of interconnection on NSTAR's Transmission System where capacity and energy will be made available to NSTAR by the Delivering Party under this Local Service Schedule. The Point(s) of Receipt shall be specified in the Transmission Service Agreement.

1.23 Service Year

The calendar year in which the Transmission Customer is receiving service under this Local Service Schedule.

1.24 Short-Term Firm Local Point-To-Point Service

Firm Local Point-To-Point Service under this Local Service Schedule with a term of less than one year.

1.25 Transmission System

The facilities owned, controlled or operated by NSTAR that are used to provide transmission service under this Local Service Schedule.

2.0 ANCILLARY SERVICES

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. NSTAR is required to provide and the Transmission Customer is required to purchase the following Ancillary Services (i) Scheduling, System Control and Dispatch, and (ii) Supplemental End-Use Reactive Support Service.

In addition, the Transmission Customer is required to purchase additional Ancillary Services under the terms and conditions of the Tariff. The Transmission Customer may not decline the Transmission Provider's offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it

will purchase from the Transmission Provider. A Transmission Customer that exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or an Eligible Customer that uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved is required to pay for all of the Ancillary Services identified in this section that were provided by the Transmission Provider associated with the unreserved service. The Transmission Customer or Eligible Customer will pay for Ancillary Services based on the amount of transmission service it used but did not reserve. NSTAR shall also assess a penalty for any unauthorized use of Ancillary Services by the Transmission Customer, based on the amount of transmission service it used but did not reserve, using the rate shown for such Ancillary Service.

The prices and/or compensation methods for Local System Control and Dispatch Services and Supplemental End-Use Reactive Support Service are described in Attachment D and Schedule 2, respectively, attached to and made a part of this Local Service Schedule. Three principal requirements apply to discounts for Ancillary Services provided by NSTAR in conjunction with its provision of transmission service as follows: (1) any offer of a discount made by NSTAR must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. A discount agreed upon for an Ancillary Service must be offered for the same period to all Eligible Customers on NSTAR's system.

3.0 CREDITWORTHINESS

NSTAR's creditworthiness procedures are specified in Attachment L to this Local Service Schedule.

4.0 BILLING AND PAYMENT

4.1 Billing Procedure

Within a reasonable time after the first day of each month, NSTAR shall submit an invoice to the Transmission Customer for the charges for all services furnished under this Local Service Schedule during the preceding month. The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to NSTAR, or by wire transfer to a bank named by NSTAR.

Billings hereunder shall be based on cost estimates made by NSTAR subject to Annual True-up

when actual costs for the Service Year are known. Such Annual True-up shall occur no later than six (6) months after the close of the Service Year to which the Annual True-up relates. To the extent bill adjustments are required pursuant to the Annual True-up, such adjustments shall bear interest calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii).

(i) The Annual True-Up shall be performed by recalculation of the costs for the Service Year based on actual cost and load information as reported in the FERC Form 1 for that Service Year and shall develop thereby an Embedded Cost Charge, defined in Section 16.1, to be used in the said Annual True-Up. The Annual True-Up shall also include the CWIP Supplement referred to in clause (ix).

(ii) The Annual True-Up will be filed with FERC by NSTAR in an informational filing on or before May 31 of the year following the Service Year and posted on NSTAR's website. The Annual True-Up so filed and posted shall include the actual report showing the basis for the computation of the Postretirement Benefits Other Than Pensions ("PBOP") component of "Administrative and General Expense" and shall also show the basis for the allocation of the PBOP expense to the service provided under this Local Service Schedule; provided that the information so filed and posted shall not include confidential information. The informational filing shall include a Benefits Labor Loader showing the basis for such allocation of both PBOP and prepaid pension costs. On request, NSTAR shall provide any Network Customer the Annual True-Up by May 31 of the year following the Service Year. Any difference between the estimated Embedded Cost Charge and the actual Embedded Cost Charge shall be collected from or refunded to the Network Customer in the month of June of the calendar year following the Service Year.

(iii) The Annual True-Up provided pursuant to Section 4.1(ii) shall include an attestation by a Company officer that "to the best of the affiant's knowledge, information and belief the data employed in the Annual True-Up reflect NSTAR's per book costs for the Service Year, conform to NSTAR's FERC Form 1 Report for the Service Year, conform in all material respects to the FERC Uniform System of Accounts, and have been developed in accordance with the provisions of this rate schedule."

(iv) The Annual True-Up shall also be accompanied by supplementary information which

shall (i) detail any data used in the Annual True-Up not directly taken from NSTAR's FERC Form 1 Report and (ii) identify any FERC Form 1 Account used to record expenses during the Service Year that was not used in the preceding Service Year. The supplementary information shall be certified by an officer of NSTAR.

(v) There shall be an "Audit Period" that will extend from July 1 through September 30 of the year following the Service Year; provided that NSTAR and the Network Customer may agree to extend the Audit Period beyond September 30 by their mutual written agreement. During the Audit Period, any Network Customer shall have the right to conduct an audit or other inspection of the actual data used in the Annual True-Up and/or request additional information not included with the Annual True-Up. NSTAR shall not withhold information, including PBOP information, on grounds of confidentiality, but is entitled to make such information available pursuant to a confidentiality agreement and to restrict access to non-competitive duty personnel and to other personnel whose receipt of the information would not be in violation of the Standards and/or Code of Conduct as prescribed by FERC. During the Audit Period, NSTAR shall exercise all commercially reasonable efforts to provide the Network Customer, within 10 business days, such additional information as the Network Customer may request in order to understand the Annual True-Up. To the extent requested, NSTAR shall meet with any Network Customer to provide such additional information, explanation, and/or clarification regarding the Annual True-Up as the Network Customer may request.

(vi) During the Audit Period, the Network Customer shall have the right to request NSTAR to adjust the Annual True-Up, and any refunds it received or payments it made, pursuant to the Annual True-Up to the extent of any discrepancy between the data employed by NSTAR in performing the Annual True-Up and the actual data for the Service Year or in the event NSTAR developed the Annual True-Up in a manner that is inconsistent with this rate schedule.

(vii) If NSTAR does not agree to the Network Customer's request, as set forth in subparagraph (vi), and if NSTAR and the Network Customer are in disagreement as to any component of the Annual True-Up, the Network Customer within thirty days following the conclusion of the Audit Period may request and NSTAR shall agree to non-binding dispute resolution either conducted with the FERC Staff or otherwise at the Network Customer's choice. The Network Customer may file a complaint with the Commission within thirty days following completion of the audit period or the dispute resolution process and shall specify in that

complaint the component or components of the Annual True Up that the Network Customer disputes. In the event such a complaint is filed, the disputed component or components of the Annual True Up shall be subject to refund as of the first day of the Service Year pending the results of the Commission investigation instituted as a result of such complaint. If the Network Customer fails to object to the Annual True-Up within thirty days following conclusion of the Audit Period, NSTAR's costs for the Service Year shall be deemed final, and its revenues from the Network Customer for the Service Year shall not be subject to refund; provided that the deadline for such an objection shall (i) be extended for ninety days following the date NSTAR makes any subsequent change to its Form 1 data for the Service Year that affects the Annual True-Up and (ii) shall not apply if the Commission prior to December 31st of the calendar year following the Service Year institutes its own investigation of NSTAR's Service Year costs.

(viii) Subject to the limitation that the Massachusetts Attorney General does not make or receive transmission payments or refunds, the Massachusetts Attorney General shall have the same procedural rights under this Section 4.0 as a Network Customer. This in no way obligates the Massachusetts Attorney General to the dispute resolution or arbitration procedures outlined in Sections 5.1 and 5.2.

(ix) The Annual True-Up shall include a CWIP Supplement, which shall apply to the Service Year, shall be filed with FERC by NSTAR in an informational filing on or before June 30 of the year following the Service Year and posted on NSTAR's website to the extent it does not include critical energy infrastructure information or other confidential information. The CWIP Supplement shall include NSTAR Electric's most recent annual construction forecast. The CWIP Supplement shall provide for each project included in rate base during the Service Year the actual amounts of CWIP recorded for each project, the related accounts, such as AFUDC and regulatory liability, inclusive of all subaccounts, and the resulting effect on the CWIP revenue requirement in line item detail. The CWIP Supplement shall also identify any changes in NSTAR's accounting practices related to the accrual of AFUDC and the inclusion of CWIP in rate base or related to ensuring that AFUDC is not accrued on CWIP balances that have been included in rate base.

For each "new project" (a project that is estimated to enter rate base for the first time in the Service Year), the CWIP Supplement shall provide, to the extent not included in the construction forecast, a detailed statement of the reasons for undertaking the project, the benefits to be derived

from the project, and the alternatives to or consequences of not undertaking the project. For each "pre-existing project" (a project that entered rate base prior to the Service Year), the CWIP Supplement shall include an update on the status of the project including any material change regarding the estimated cost of the project, the estimated in-service date and/or project timelines, and whether there is any change in the need for the project or in alternatives to the project. CWIP associated with a project cannot be included in the rate base for a Service Year unless it is included in the CWIP Supplement applicable to the Service Year.

The CWIP Supplement applicable to a Service Year shall include a CWIP Work Order/Project Reference Aid ("Reference Aid") that distinguishes between new projects and pre-existing projects and that provides for each project, whether new or pre-existing, ISO information, to the extent such information is available and applies to a project, and NSTAR information. The ISO information shall include a short description of the project, the year the project was approved through the ISO process, and the project identification number for ISO purposes. The NSTAR information shall include reference to the most recent NSTAR construction planning forecast in which the project appeared, the page of the plan at which the project description begins, the NSTAR numeric project designation, the NSTAR description of the project, the work order or work orders associated with the project, and a description of each work order. The Reference Aid shall present this information in a format so that the ISO information related to a project can be correlated with the NSTAR information related to a project. The Reference Aid, as described above, is based on current ISO and NSTAR tracking systems for projects under or proposed for construction and is to be modified to present equivalent information if and to the extent the ISO and/or NSTAR tracking system is modified.

The 50% of transmission-related CWIP included in rate base is subject to the Annual True-Up and dispute resolution provisions of this Section 4.1 regarding differences between actual and estimated costs. In addition, the CWIP included in rate base for a project shall be subject to refund as provided below to the extent the Commission makes a finding that the inclusion of such CWIP in rate base is unjust and unreasonable. In the case of a new project, the refund amount shall be the CWIP actually recovered from customers from the date of collection to the date of refund. In any proceeding regarding a new project, NSTAR shall bear the burden of proving that inclusion of CWIP related to the new project in rate base is just and reasonable. In the case of a pre-existing project, the refund amount shall be for the CWIP actually recovered from customers from the prospective refund effective date specified by the Commission pursuant to the

provisions of Section 206 of the Federal Power Act to the date of refund. All refunds shall include interest at the rate specified in 18 C.F.R. § 35.19a(a)(2)(iii). Any customer and/or the Massachusetts Attorney General can request that the Commission institute an investigation into the justness and reasonableness of including CWIP for any project in rate base and the Commission may institute such an investigation sua sponte.

Nothing in this Clause (ix) authorizes the inclusion in rate base of more than 50% of the CWIP balance attributable to a project. Absent a Commission finding of imprudence, NSTAR shall be entitled to accrue AFUDC as to any CWIP that is excluded from rate base. The Commission's institution of an investigation as to the justness and reasonableness of including CWIP associated with a project in rate base does not affect the timing or the finality of other components of the Annual True-Up as established by clause (vii) hereof.

With the exception of curtailment penalty charges pursuant to Section 16.2 and Schedule 3, paragraph 5 and Schedule 4, paragraph 6, any Annual True-Up rendered under this Local Service Schedule and any other monthly bill to which the Annual True-Up relates shall be binding on both Parties one (1) year from the date of NSTAR's Annual True-Up, unless previously disputed pursuant to this section or Section 4.3 of this Local Service Schedule.

4.2 Interest on Unpaid Balances

Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by NSTAR.

4.3 Customer Default

In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to NSTAR on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after NSTAR notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, NSTAR may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request.

In the event of a billing dispute between NSTAR and the Transmission Customer, NSTAR will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then NSTAR may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

5.0 DISPUTE RESOLUTION PROCEDURES

5.1 Internal Dispute Resolution Procedures

Any dispute between a Transmission Customer and NSTAR involving transmission service under this Local Service Schedule (excluding applications for rate changes or other changes to this Local Service Schedule, or to any Service Agreement entered into under this Local Service Schedule, which shall be presented directly to the Commission for resolution) shall be referred to a designated senior representative of NSTAR and a senior representative of the Transmission Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days [or such other period as the Parties may agree upon] by mutual agreement, such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below.

5.2 External Arbitration Procedures

Any arbitration initiated under this Local Service Schedule shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) days of the referral of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association and any applicable Commission regulations or ISO rules.

5.3 Arbitration Decisions

Unless otherwise agreed, the arbitrator(s) shall render a decision within ninety (90) days of appointment and shall notify the Parties in writing of such decision and the reasons therefore. The arbitrator(s) shall be authorized only to interpret and apply the provisions of this Local Service Schedule and any Service Agreement entered into under this Local Service Schedule and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act and/or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with the Commission if it affects jurisdictional rates, terms and conditions of service or facilities.

5.4 Costs

Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable:

(a) the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or

(b) one half the cost of the single arbitrator jointly chosen by the Parties.

5.5 Rights Under The Federal Power Act

Nothing in this section shall restrict the rights of any party to file a complaint with the Commission under relevant provisions of the Federal Power Act.

II LOCAL POINT-TO-POINT SERVICE

6.0 NATURE OF FIRM LOCAL POINT-TO-POINT SERVICE

6.1 Curtailment of Firm Local Point-To-Point Service

In the event a Transmission Customer (including Third-Party Sales by NSTAR) fails to curtail a transaction when requested to do so by NSTAR, the Local Control Center and/or ISO, as

appropriate and pursuant to this Section, NSTAR shall assess a penalty charge to the Transmission Customer. Said penalty charge will be determined in accordance with this Local Service Schedule.

In the event NSTAR, the Local Control Center or ISO exercises their rights to effect a Curtailment, in whole or in part, of Firm Local Point-To-Point Service, no credit or other adjustment shall be provided as a result of the Curtailment with respect to the charge payable by the Transmission Customer.

6.2 Classification of Firm Local Point-To-Point Service

(a) The Transmission Customer taking Firm Local Point-To-Point Service may, (1) change its Points of Receipt and Delivery to obtain service on a non-firm basis consistent with the terms of Part I, Section 10(a) of Schedule 21 of the OATT or (2) request a modification of the Points of Receipt or Delivery on a firm basis pursuant to the terms of Part I, Section 10(b) of Schedule 21 of the OATT; provided that NSTAR continues to be compensated for any costs associated with the construction or upgrading of facilities associated with the original firm service.

(b) In the event that a Transmission Customer's use of the Transmission System (including Third-Party Sales by NSTAR) exceeds that Transmission Customer's Reserved Capacity at any Point of Receipt or Point of Delivery in any hour, NSTAR will charge the Transmission Customer a penalty charge in accordance with Section 10 and Schedule 3 of this Local Service Schedule.

(c) Under no circumstance will NSTAR be obligated to provide Control Area Ancillary Services to the Transmission Customer in support of any excess capacity (i.e., capacity in excess of Transmission Customer's Reserved Capacity).

7.0 NATURE OF NON-FIRM LOCAL POINT-TO-POINT SERVICE

7.1 Classification of Non-Firm Local Point-To-Point Service

In the event that a Transmission Customer's use of the Transmission System (including Third-Party Sales by NSTAR) exceeds that Transmission Customer's non-firm Reserved Capacity at any Point of Receipt or Point of Delivery, NSTAR will charge the Transmission

Customer a penalty charge in accordance with Section 10 and Schedule 4 of this Local Service Schedule for such excess. Under no circumstance will NSTAR be obligated to provide Control Area Ancillary Services to the Transmission Customer in support of any excess capacity (i.e., capacity in excess of Transmission Customer's Reserved Capacity).

7.2 Curtailment or Interruption of Service

In the event a Transmission Customer (including Third-Party Sales by NSTAR) fails to implement a Curtailment or Interruption when requested to do so by NSTAR, the Local Control Center and/or ISO, as appropriate and pursuant to this Section, NSTAR shall assess a penalty charge. Said penalty charge will be determined in accordance with Section 10 and Schedule 4 of this Local Service Schedule.

In the event NSTAR, the Local Control Center and/or ISO exercises its rights to effect a Curtailment, in whole or part, of Non-Firm Local Point-To-Point Service, no credit or other adjustment shall be provided as a result of the Curtailment with respect to the charge payable by the Transmission Customer.

In the event NSTAR, the Local Control Center and/or ISO exercises its rights to effect an Interruption, in whole or part, of Non-Firm Local Point-To-Point Service, the charge payable by the Transmission Customer shall be computed as if the term of service actually rendered were the term of service reserved; provided that an adjustment of the charge shall be made only when the Interruption is initiated by NSTAR, the Local Control Center and/or ISO, not when the customer fails to deliver energy to NSTAR.

8.0 SERVICE AVAILABILITY

8.1 Real Power Losses

Real power losses associated with transactions on NSTAR's Local Network shall be determined based on estimated average system losses for metering points on NSTAR's Local Network; the loss factor will be three and one tenth percent (3.1%).

8.2 Load Shedding

To the extent that a system contingency exists on the NSTAR Transmission System or the New England Transmission System and NSTAR, the Local Control Center or ISO, as appropriate,

determines that it is necessary to shed load, the Parties shall shed load in accordance with the procedures specified by NSTAR, the Local Control Center and/or ISO.

9.0 METERING

Unless otherwise agreed, the Transmission Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted under the Local Service Schedule and to communicate the information to NSTAR. However, NSTAR reserves the right to determine and approve any and all metering equipment and the metering installation design, such approval not to be unreasonably withheld.

All meters, including any recording devices or telemetry equipment must be operated and maintained in accordance with ISO Operating Procedures. Unless otherwise agreed, such equipment shall remain the property of NSTAR.

If at any time any metering equipment owned by NSTAR (or the Transmission Customer, if so agreed) is found to be inaccurate in excess of two percent (2%), up or down, the owner of the metering equipment shall cause it to be made accurate or replaced and the meter readings and rate computation for the period of inaccuracy shall be adjusted to correct such inaccuracy so far as the same can be reasonably ascertained, but no adjustment prior to the beginning of the next preceding month shall be made except by agreement of the Parties. In addition to an annual routine test, the owner of the metering equipment shall cause such equipment to be tested at any time upon written request of the other Party. If such equipment proves accurate within two percent (2%), up or down, the expense of the test shall be borne by the Party requesting the test. The determination of percent accuracy shall be in accordance with the weighted average percent registration as described in ANSI C12.1-1988, Section 6.1.8.1. The owner of the metering equipment shall comply with any reasonable request of the other Party concerning the sealing of meters, the presence of a representative when the seals are broken and tests are made, and other matters affecting the accuracy of the measurement of electricity hereunder.

10.0 COMPENSATION FOR LOCAL POINT-TO-POINT SERVICE

Rates for Firm and Non-Firm Local Point-To-Point Service shall be determined as set forth in the Schedules appended to this Local Service Schedule: Firm Local Point-To-Point Service (Schedule 3) and Non-Firm Local Point-To-Point Service (Schedule 4). Such rates shall be determined on the basis of estimated costs for each Service Year until the actual costs for such Service Year are determined.

Thereafter, payments made on such estimated costs shall be recalculated based on actual data for that Service Year, and an appropriate billing adjustment shall be made pursuant to Section 4 of this Local Service Schedule.

NSTAR shall use this Local Service Schedule to make its Third-Party Sales to be transmitted as Local Point-To-Point Service. NSTAR shall account for such use at the applicable rates, pursuant to Section II.8.5 of the Tariff.

11.0 STRANDED COST RECOVERY

NSTAR may seek to recover stranded costs from the Transmission Customer pursuant to this Local Service Schedule in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, NSTAR must separately file any specific proposed stranded cost charge under Section 205 of the Federal Power Act.

III LOCAL NETWORK SERVICE

12.0 NATURE OF LOCAL NETWORK SERVICE

12.1 Real Power Losses

Real power losses associated with transactions on Non-PTF shall be determined based on estimated average system losses for metering points on NSTAR's Local Network; the loss factor will be three and one tenth percent (3.1%).

12.2 Metering

Unless agreed otherwise, all meters, including any recording devices or telemetry equipment shall be owned, operated, maintained and tested by NSTAR or its Designated Agent in accordance with ISO Operating Procedures at the Transmission Customer's expense. NSTAR shall provide access to metering data, including telephone line access, which may reasonably be required to facilitate measurement and billing under a Service Agreement at the requesting Party's expense.

NSTAR reserves the sole right to determine appropriate metering installations. When new metering equipment is required, it shall be supplied by NSTAR, at the Transmission Customer's expense, including applicable taxes, and overhead costs, in conformity with ISO Operating

Procedures.

If at any time any metering equipment owned by NSTAR (or Transmission Customer, if so agreed) is found to be inaccurate in excess of two percent (2%), up or down, the owner of the metering equipment shall cause it to be made accurate or replaced and the meter readings and rate computation for the period of inaccuracy shall be adjusted to correct such inaccuracy so far as the same can be reasonably ascertained, but no adjustment prior to the beginning of the next preceding month shall be made except by agreement of the Parties. In addition to an annual routine test, the owner of the metering equipment shall cause such equipment to be tested at any time upon written request of the other Party.

If such equipment proves accurate within two percent (2%), up or down, the expense of the test shall be borne by the Party requesting the test. The determination of percent accuracy shall be in accordance with the weighted average percent registration as described in ANSI C12.1-1988, Section 6.1.8.1. The owner of the metering equipment shall comply with any reasonable request of the other Party concerning the sealing of meters, the presence of a representative when the seals are broken and tests are made, and other matters affecting the accuracy of the measurement of electricity hereunder.

13.0 NETWORK RESOURCES

13.1 Operation of Network Resources

The Network Customer shall not operate its designated Network Resources located in the Network Customer's or NSTAR's Control Area such that the output of those facilities exceeds its designated Local Network Load, plus Non-Firm Sales delivered pursuant to Part II of this Local Service Schedule, plus losses. This limitation shall not apply to changes in the operation of a Transmission Customer's Network Resources at the request of NSTAR to respond to an emergency or other unforeseen condition which may impair or degrade the reliability of the Transmission System.

13.2 Transmission Arrangements for Network Resources Not Physically Interconnected With NSTAR

The Network Customer shall be responsible for any arrangements necessary to deliver capacity and energy from a Network Resource not physically interconnected with NSTAR's Transmission

System. NSTAR will undertake reasonable efforts to assist the Network Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice.

13.3 Use of Interface Capacity by the Network Customer

Unless otherwise provided under the Tariff, there is no limitation upon a Network Customer's use of NSTAR's Transmission System at any particular interface to integrate the Network Customer's Network Resources (or substitute economy purchases) with its Local Network Loads. However, unless otherwise provided by the Tariff, a Network Customer's use of NSTAR's total interface capacity with other transmission systems may not exceed the Network Customer's Load.

13.4 Network Customer Owned Transmission Facilities

The Network Customer that owns existing transmission facilities that are integrated with NSTAR's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration the Network Customer must demonstrate that its transmission facilities are integrated into the plans or operations of NSTAR to serve its power and transmission customers. For facilities constructed by the Network Customer subsequent to the Service Commencement Date under this Local Service Schedule, the Network Customer shall receive credit where such facilities are jointly planned and installed in coordination with NSTAR. Calculation of the credit shall be addressed in either the Network Customer's Service Agreement or any other agreement between the Parties.

14.0 DESIGNATION OF LOCAL NETWORK LOAD

14.1 Local Network Load

The Network Customer must designate the individual Local Network Loads on whose behalf NSTAR will provide Local Network Service. The Local Network Loads shall be specified in the Service Agreement.

14.2 Local Network Load Not Physically Interconnected with NSTAR

This section applies to both initial designation pursuant to Section 15.1 and the subsequent addition of new Local Network Load not physically interconnected with NSTAR. To the extent that the Network Customer desires to obtain transmission service for a load outside NSTAR's Transmission System, the Network Customer shall have the option of (1) electing to include the

entire load as Local Network Load for all purposes under this Local Service Schedule and designating Network Resources in connection with such additional Local Network Load, or (2) excluding that entire load from its Local Network Load and purchasing Local Point-To-Point Service under this Local Service Schedule.

To the extent that the Network Customer gives notice of its intent to add a new Local Network Load as part of its Local Network Load pursuant to this section, the request must be made through a modification of service pursuant to a new Application.

15.0 LOAD SHEDDING AND CURTAILMENTS

15.1 Procedures

Prior to the Service Commencement Date, NSTAR and the Network Customer shall establish Load Shedding and Curtailment procedures pursuant to the OATT with the objective of responding to contingencies on the Transmission System. The Parties will implement such programs during any period when NSTAR, the Local Control Center or ISO, as appropriate, determines that a system contingency exists and such procedures are necessary to alleviate such contingency. NSTAR will notify all affected Network Customers in a timely manner of any scheduled Curtailment.

15.2 Allocation of Curtailments

NSTAR shall, on a non-discriminatory basis, effect a Curtailment of the transaction(s) that effectively relieves the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by NSTAR and Network Customer in proportion to their respective Load Ratio Shares. NSTAR shall not direct the Network Customer to effect a Curtailment of schedules to an extent greater than NSTAR would effect a Curtailment of NSTAR’s schedules under similar circumstances.

15.3 Load Shedding

To the extent that a system contingency exists on NSTAR’s Transmission System and ISO, the Local Control Center or NSTAR, as appropriate, determines that it is necessary for NSTAR, Local Point-to-Point Customers and Network Customers to shed load, the Parties shall shed load in accordance with the OATT.

15.4 System Reliability

Any Curtailment of Local Network Service will be not unduly discriminatory relative to NSTAR's use of the Transmission System on behalf of its Native Load Customers. In the event that the Network Customer fails to respond to established Load Shedding and Curtailment procedures, NSTAR shall assess a penalty charge. Said penalty charge will be determined in accordance with Section 16.2.

16.0 RATES AND CHARGES

Rates for Local Network Service shall be determined as set forth in this Section 16 on the basis of estimated costs for each Service Year until the actual costs for such Service Year are determined. Thereafter, payments made on such estimated costs shall be recalculated based on actual data for that Service Year, and all appropriate billing adjustments shall be made pursuant to Section 4 of this Local Service Schedule.

The Network Customer shall pay NSTAR for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following:

16.1 Monthly Demand Charge

The Network Customer shall pay a Monthly Demand Charge which shall be the Embedded Cost Charge. The Embedded Cost Charge shall be determined by multiplying the Network Customer's Load Ratio Share by one twelfth (1/12) of NSTAR's Annual Transmission Revenue Requirements, as determined in accordance with Attachment D of this Local Service Schedule and as subject to an Annual True-up pursuant to Section 4. The Embedded Cost Charge is based on NSTAR's system average embedded cost. In the event NSTAR seeks to apply a rate based on a methodology other than average embedded cost to all or any part of a Network Customer's service, either already being provided or proposed to be provided, NSTAR shall provide the affected Network Customer thirty days advance written notice of any filing with the Commission seeking to implement such a rate and shall comply with all applicable requirements of the Commission and the Tariff. Any dispute as to NSTAR's position concerning proposed cost allocation shall be addressed as provided in Section II.7(g) of Schedule 21-Local Service to Section II of the Tariff; provided that nothing in this provision prevents NSTAR from filing with the Commission at any time to establish new rates pursuant to the provisions of Section 205 of the FPA or a Network Customer from opposing such a filing, and nothing in this provision is intended to reflect a Network Customer's agreement that NSTAR has the rights set out in this

Section 16.1 or is intended to prevent the affected Network Customer from filing a complaint with the Commission at any time pursuant to the provisions of Section 206 of the FPA or NSTAR from opposing such a filing.

16.2 Curtailment Penalty Charge

If the Transmission Customer fails to respond to established emergency load shedding and curtailment procedures to relieve emergencies on the transmission system, NSTAR may assess a penalty charge to the Transmission Customer. Said penalty charge will be equal to two (2) times the Monthly Demand Charge for Local Network Service, as calculated in accordance with Section 16.1 of this Local Service Schedule, for the month in which such service was not curtailed or interrupted.

16.3 [Reserved]

16.4 Taxes and Fees Charge

16.4.1 If NSTAR incurs tax liability currently for which it will in subsequent years receive tax benefits (for example, a taxable contribution in aid of construction) then Transmission Customer shall pay to NSTAR an amount sufficient to reimburse NSTAR, on a net present value basis, for the reasonably projected costs resulting from the tax liability incurred in the current year less the reasonably projected tax benefits received by NSTAR in future years. Sections 16.4.1 and 16.4.2 are intended to apply to those Transmission Customers for whom Direct Assignment Facilities are constructed pursuant to this Local Service Schedule and to any Transmission Customer's appropriate share of the cost of any required Local Network Upgrades to the extent that any such Local Network Upgrade is identified pursuant to the study procedures outlined in Schedule 21-Local Service, Section II.7(d) and permitted or required by Commission ruling to be paid as a contribution in aid of construction.

16.4.2 If NSTAR takes a position that any particular transaction under any section of the Local Service Schedule does not constitute a transaction of the type described immediately above, and that position is subsequently reversed by Treasury ruling or regulation or court action, then the Transmission Customer shall pay to NSTAR an amount calculated as described above, but additionally taking into account any interest assessment required

to be paid by NSTAR.

16.4.3 At its effective date, this Section 16.4 applies only to contributions in aid of construction ("CIAC"). NSTAR reserves the right to file under Section 205 of the FPA to modify this provision to apply to items other than CIAC and the Network Customer reserves the right to oppose any such filing.

17.0 OPERATING ARRANGEMENTS

17.1 Operating Requirements

The terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of this Local Service Schedule shall be specified in the OATT. The OATT shall provide for the Parties to:

(i) operate and maintain equipment necessary for integrating the Network Customer within NSTAR's Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment),

(ii) transfer data between NSTAR and the Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside NSTAR's Transmission System, interchange schedules, unit outputs for redispatch required under Section 15, voltage schedules, loss factors and other real time data),

(iii) use software programs required for data links and constraint dispatching,

(iv) exchange data on forecasted loads and resources necessary for long-term planning, and

(v) address any other technical and operational considerations required for implementation of this Local Service Schedule, including scheduling protocols.

The OATT will recognize that the Network Customer shall either:

(i) operate as a Control Area under applicable guidelines of the Electric Reliability Organization (ERO), as defined in 18 CFR 38.1, and ISO,

(ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with NSTAR, or

(iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies the applicable reliability guidelines of the ERO and ISO. NSTAR shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services.

17.2 Network Operating Committee

A Network Operating Committee (Committee) shall be established to coordinate operating criteria for the Parties' respective responsibilities under the OATT. Each Network Customer shall be entitled to have at least one representative on the Committee. The Committee shall meet from time to time as need requires, but no less than once each calendar year.

SCHEDULE 2

SUPPLEMENTAL END-USE REACTIVE SUPPORT SERVICE

In the event that power factor levels and reactive supply requirements set forth in the service agreement or other associated operating or interconnect agreement are not maintained by the Delivering Party (or, as appropriate, the Receiving Party), in accordance with applicable ISO standards and practices then NSTAR shall charge the Transmission Customer to take corrective action. The Transmission customer shall compensate NSTAR for installing the necessary equipment, whether in the form of generating units or other non-generating resources, such as demand resources, to correct the incremental difference between the Transmission Customer's lowest (or highest) power factor level and that which is an acceptable level in accordance with ISO standards and practices. The charges will be based upon the necessary level of reactive power supply required to correct the deficiency in the power factor level.

For the KVAR demand supplied to the Transmission Customer, the charge shall be the greater of a) the market price of installing leading reactive power supply expressed in terms of $/KVAR or b) $50/KVAR of installed (leading) reactive power reflecting current NSTAR cost.

For the KVAR demand absorbed by NSTAR the charge shall be the greater of a) the market price of installing lagging reactive power supply expressed in terms of $/KVAR or b) $22.5/KVAR of installed (lagging) reactive power reflecting current NSTAR cost.

SCHEDULE 3

LONG-TERM FIRM AND SHORT-TERM FIRM

LOCAL POINT-TO-POINT SERVICE

The Transmission Customer shall compensate NSTAR for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following charges as applicable:

1) Annual Rate

The Annual Rate for Firm Local Point-To-Point Service shall consist of the higher of (i) the Embedded Cost Charge or (ii) the Incremental Cost Charge, as set forth below:

(i) The Embedded Cost Charge shall be determined by dividing NSTAR's Annual Transmission Revenue Requirements (determined in accordance with Attachment D of this Local Service Schedule) by the maximum amount of NSTAR's Monthly Transmission System Load during such Service Year.

(ii) The Incremental Cost Charge shall be determined from the total costs of all Local Network Upgrades plus other incremental costs incurred provided for in the Service Agreement application to a transaction. If the Incremental Cost Charge is higher, the Transmission Customer shall pay for the facilities necessary to provide it with service during an amortization period, with the Transmission Customer paying the Embedded Cost Charge upon completion of the amortization. Such amortization period shall be coterminous with the Service Agreement.

2) Firm Local Point-To-Point Service for Monthly Transactions or Longer Term Transactions

The charge for each month applicable to a monthly transaction or longer term transaction (the "Monthly Rate") shall be determined as the product of: (a) NSTAR's Annual Rate for Firm Local Point-To-Point Service divided by twelve (12) months and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Service Agreement for such month, expressed in kilowatts.

3) Firm Local Point-To-Point Service for Less Than One Month

NSTAR's Weekly Rate is equal to NSTAR's Annual Rate for Firm Local Point-To-Point Service divided by fifty-two (52) weeks. NSTAR's Daily Rate is equal to NSTAR's Annual Rate for Firm Local Point-To-Point Service divided by three hundred and sixty-five (365) days. NSTAR's Hourly Rate is equal to

NSTAR's Annual Rate for Firm Local Point-To-Point Service divided by eight thousand seven hundred and sixty (8,760) hours.

The Transmission Customer shall pay the Weekly, Daily or Hourly Rate, as applicable, times the Reserved Capacity set forth in the Transmission Customer's Applicable Service Agreement.

4) Penalty

When the Transmission Customer exceeds its Reserved Capacity or uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved (Excess Incident), NSTAR will charge the Transmission Customer 200% of the rate determined as follows for each kilowatt of the Excess Incident:

- The unreserved use penalty for a single hour of unreserved use shall be based on the rate for daily Firm Point-to Point Transmission Service.

- If there is more than one assessment for a given duration (e.g., daily) for the Transmission Customer, the penalty shall be based on the next longest duration (e.g., weekly).

- The unreserved penalty charge for multiple instances of unreserved use (i.e., more than one hour) within a day shall be based on the daily rate for Firm Point-To-Point Transmission Service.

- The unreserved penalty charge for multiple instances of unreserved use isolated to one calendar week shall be based on the charge for weekly Firm Point-To-Point Transmission Service.

- The unreserved use penalty charge for multiple instances of unreserved use during more than one week during a calendar month shall be based on the charge for monthly Firm Point-To-Point Transmission Service.

- The unreserved use penalty charge for multiple instances of unreserved use during more than one month during a calendar year shall be based on the charge for yearly Firm Point-To-Point Transmission Service.

All Excess Incidents will be recorded by NSTAR, and if in any calendar year more than ten (10) Excess Incidents occur in connection with service for the Transmission Customer, then NSTAR may require the Transmission Customer to apply for additional Firm Local Point-To-Point Service under this Local

Service Schedule in the amount equal to the highest Excess Incident during that Service Year. Charges for such additional transmission service will relate back to the first day of the month following the month of NSTAR's notice.

5) Curtailment Penalty Charge

If the Transmission Customer fails to respond to established emergency load shedding and curtailment procedures to relieve emergencies on the Transmission System, NSTAR may assess a penalty charge to the Transmission Customer. Said penalty charge will be equal to two (2) times the Monthly Rate for Firm Local Point-To-Point Service for the month in which such service was not curtailed or interrupted.

6) Taxes and Fees Charge

A) If any governmental authority requires the payment of any fee or assessment not specifically provided for in any of the charge or rate provisions under this Local Service Schedule or imposes a sales, gross revenue, or other form of tax with respect to payments made for service provided under this Local Service Schedule, including any applicable interest charged on any deficiency assessment made by the taxing authority, together with any further tax on such payments, the obligation to make payment for any such fee, assessment, or tax shall be borne by the Transmission Customer. NSTAR will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's Regulations.

B) If NSTAR incurs tax liability currently for which it will, in subsequent years, receive tax benefits (for example, a taxable contribution in aid of construction), the Transmission Customer shall pay to NSTAR an amount sufficient to reimburse NSTAR, on a net present value basis, for the reasonably projected costs resulting from the tax liability incurred in the current year less the reasonably projected tax benefits received by NSTAR in future years.

C) If NSTAR takes a position that any particular transaction under any section of this Local Service Schedule does not constitute a transaction of the type described immediately above, and that position is subsequently reversed by Treasury ruling or regulation, or court action, then the Transmission Customer shall pay to NSTAR an amount calculated as described above but additionally taking into account any interest assessment required to be paid by NSTAR.

7) Regulatory Expense Charge

NSTAR shall have the right to make a Section 205 filing for recovery of regulatory expenses associated with this Local Service Schedule and the Service Agreement(s).

8) Customer-Related Expense Charge

NSTAR shall charge the Transmission Customer, in addition to the other charges assessed pursuant to this Local Service Schedule, and as set forth in its Service Agreement for those costs attributable to the billing, meter reading, record keeping, (all from FERC Uniform System of Accounts Nos. 901-905) and an allocation of administrative and general expenses (FERC Uniform System of Accounts Nos. 920-935) associated with each of these costs, all of which are related to the Transmission Customer's Local Point-To-Point Service and allocated on the basis of the total number of customers served by NSTAR.

9) Exchanges

With respect to any transactions that involve an exchange, each party to such transaction shall be an individual Transmission Customer under this Local Service Schedule. Accordingly, a transmission charge, as applicable, will be calculated for, and a separate bill will be rendered to, each such Transmission Customer.

10) Discounts

Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by NSTAR must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, NSTAR must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

11) Resales

The rates and rules governing charges and discounts shall not apply to resales of transmission service, compensation for which shall be governed by § I.11(a) of Schedule 21.

SCHEDULE 4

NON-FIRM LOCAL POINT-TO-POINT SERVICE

The Transmission Customer shall compensate NSTAR for any Ancillary Services and for Non-Firm Local Point-To-Point Service up to the sum of the applicable charges set forth below:

1) The Annual Rate for Non-Firm Local Point-To-Point Service shall be NSTAR's Annual Transmission Revenue Requirements (determined in accordance with Attachment D of this Local Service Schedule) for the Service Year divided by NSTAR's Monthly Transmission System Load during such Service Year.

2) Non-Firm Local Point-To-Point Service for Monthly Transactions or Longer Term Transactions

The charge for each month applicable to a monthly transaction or longer term transaction (the "Monthly Rate") shall be determined as the product of: (a) NSTAR's Annual Rate for Non-Firm Local Point-To-Point Service divided by twelve (12) months and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Service Agreement for such month, expressed in kilowatts.

3) Non-Firm Local Point-To-Point Service for Less Than One Month

NSTAR's Weekly Rate is equal to NSTAR's Annual Rate for Non-Firm Local Point-To-Point Service divided by fifty-two (52) weeks.

NSTAR's Daily Rate is equal to NSTAR's Annual Rate for Non-Firm Local Point-To-Point Service divided by three hundred and sixty-five (365) days. NSTAR's Hourly Rate is equal to NSTAR's Annual Rate for Non-Firm Local Point-To-Point Service divided by eight thousand seven hundred and sixty (8,760) hours.

The Transmission Customer shall pay the Weekly, Daily or Hourly Rate, as applicable, time the Reserved Capacity set forth in the Transmission Customer's Applicable Service Agreement.

4) Credit to the Transmission Charge

Whenever service provided hereunder is interrupted or curtailed by NSTAR, or its Designated Agent including ISO, the Transmission Charges to the Transmission Customer calculated pursuant to Sections 2 and 3 of this Schedule 4 shall be credited by an amount equal to the sum of the credits calculated for each hour of interruption or curtailment in service. The credit to the Transmission Customer for each hour of

interruption or curtailment shall be calculated as the product of (a) NSTAR's Hourly Rate and (b) the kilowatts of service interruption or curtailment during such hour.

5) Penalty

When the Transmission Customer exceeds its Reserved Capacity or uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved (Excess Incident), NSTAR will charge the Transmission Customer 200% of the rate determined as follows for each kilowatt of the Excess Incident:

- The unreserved use penalty for a single hour of unreserved use shall be based on the rate for daily Firm Point-to Point Transmission Service.

- If there is more than one assessment for a given duration (e.g., daily) for the Transmission Customer, the penalty shall be based on the next longest duration (e.g., weekly).

- The unreserved penalty charge for multiple instances of unreserved use (i.e., more than one hour) within a day shall be based on the daily rate for Firm Point-To-Point Transmission Service.

- The unreserved penalty charge for multiple instances of unreserved use isolated to one calendar week shall be based on the charge for weekly Firm Point-To-Point Transmission Service.

- The unreserved use penalty charge for multiple instances of unreserved use during more than one week during a calendar month shall be based on the charge for monthly Firm Point-To-Point Transmission Service.

- The unreserved use penalty charge for multiple instances of unreserved use during more than one month during a calendar year shall be based on the charge for yearly Firm Point-To-Point Transmission Service.

All Excess Incidents will be recorded by NSTAR, and if in any calendar year more than ten (10) Excess Incidents occur in connection with service for the Transmission Customer, then NSTAR may require the Transmission Customer to apply for additional Non-Firm Local Point-To-Point Service under this Local Service Schedule in the amount equal to the highest Excess Incident during that Service Year. Charges for such additional Non-Firm Local Point-To-Point Service will relate back to the first day of the month following the month of NSTAR's notice.

6) Curtailment Penalty Charge.

If the Transmission Customer fails to respond to established emergency load shedding and curtailment procedures to relieve emergencies on the Transmission System, NSTAR may assess a penalty charge to the Transmission Customer. Said penalty charge will be equal to two (2) times the monthly demand charge for Non-Firm Local Point-To-Point Service for the month in which such service was not curtailed or interrupted.

7) Taxes and Fees Charge

A) If any governmental authority requires the payment of any fee or assessment not specifically provided for in any of the charge or rate provisions under this Local Service Schedule or imposes a sales, gross revenue, or other form of tax with respect to payments made for service provided under this Local Service Schedule, including any applicable interest charged on any deficiency assessment made by the taxing authority, together with any further tax on such payments, the obligation to make payment for any such fee, assessment, or tax shall be borne by the Transmission Customer. NSTAR will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's Regulations.

B) If NSTAR incurs tax liability currently for which it will, in subsequent years, receive tax benefits (for example, a taxable contribution in aid of construction), the Transmission Customer shall pay to NSTAR an amount sufficient to reimburse NSTAR, on a net present value basis, for the reasonably projected costs resulting from the tax liability incurred in the current year less the reasonably projected tax benefits received by NSTAR in future years.

C) If NSTAR takes a position that any particular transaction under any section of this Local Service Schedule does not constitute a transaction of the type described immediately above, and that position is subsequently reversed by Treasury ruling or regulation, or court action, then the Transmission Customer shall pay to NSTAR an amount calculated as described above but additionally taking into account any interest assessment required to be paid by NSTAR.

8) Regulatory Expense Charge

NSTAR shall have the right to make a Section 205 filing for recovery of regulatory expenses associated with this Local Service Schedule and the Service Agreement(s).

9) Customer-Related Transaction Charge

NSTAR shall charge the Transmission Customer, in addition to the other charges assessed pursuant to this Local Service Schedule, and as set forth in its Service Agreement for those costs attributable to the billing, meter reading, record keeping, (from FERC Uniform System of Accounts Nos. 901-905) and an allocation of administrative and general expenses (Nos. 920-935) associated with each of these costs, all of which are related to the Transmission Customer's Local Point-To-Point Service and allocated on the basis of the total number of customers served by NSTAR.

10) Exchanges

With respect to any transactions that involve an exchange, each party to such transaction shall be an individual Transmission Customer under this Local Service Schedule. Accordingly, a transmission charge, as applicable, will be calculated for, and a separate bill will be rendered to, each such Transmission Customer.

11) Discounts

Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by NSTAR must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, NSTAR must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

12) Resales

The rates and rules governing charges and discounts shall not apply to resales of transmission service, compensation for which shall be governed by § I.11(a) of Schedule 21.

ATTACHMENT A

METHODOLOGY TO ASSESS AVAILABLE TRANSFER CAPABILITY

1. Introduction

ISO is the regional transmission organization ("RTO"), serving the New England Control Area. ISO is responsible for development, oversight, and fair administration of New England's wholesale market and management of bulk electric power system and wholesale markets' planning processes. The ISO serves as the Balancing Authority for the New England Control Area. The New England Control Area is interconnected to three neighboring Balancing Authority Areas: New Brunswick System Operator Area ("NBSO Area"), New York Independent System Operator Area ("NYISO Area"), and Hydro-Québec TransÉnergie Area ("HQTÉ Area").

As part of its RTO responsibilities, the ISO is registered with the North American Electric Reliability Corporation ("NERC") as several functional model entities that have responsibilities related to the calculation of ATC as defined in the following NERC Standards: MOD-001 – Available Transmission System Capability ("MOD-001"), MOD-004 – Capacity Benefit Margin ("MOD-004"), and MOD-008 – Transmission Reliability Margin Calculation Methodology ("MOD-008"). The extent of those responsibilities is based on various Commission-approved transmission operating agreements and the provisions of the ISO New England Operating Documents.

While the ISO is the transmission provider for transmission service associated with PTF, the Participating Transmission Owners (PTOs) under the Transmission Operating Agreement, such as NSTAR, provide local transmission service over Non-Pool Transmission Facilities within the RTO footprint and are responsible for calculating TTC and ATC associated with Local Service provided under Schedule 21. Pursuant to CFR § 37.6(b)[1]of the Commission's regulations, NSTAR as a Transmission Provider is obligated to calculate and post ATC and TTC for certain local facilities over which Point-to-Point transmission service is provided under Schedule 21-NSTAR. These are primarily radial paths that provide transmission service to directly interconnected generators.

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[1]§37.6(b) Posting transfer capability. The available transfer capability (ATC) on the Transmission Provider's system and the total transfer capability (TTC) of that system shall be calculated and posted for each Posted Path as set forth in this section.

Posted Path is defined as any control area-to-control area interconnection; any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a

customer requests to have ATC or TTC posted. For this last category, the posting must continue for 180 days and thereafter until 180 days have elapsed from the most recent request for service over the requested path. For purposes of this definition, an hour includes any part of any hour during which serviced was denied, curtailed or interrupted. §37.6(b)(1)(i).

NSTAR does not currently have any Posted Paths based on the above definition. However, to the extent that NSTAR does in the future have any Posted Path(s), NSTAR will calculate ATC and TTC using NERC Standard MOD-029-1 Rated System Path Methodology as outlined below.

1.1 Scope of Document

The scope of this document is limited to the following functions which are performed or utilized by NSTAR in order to provide Local Point-to Point Service under Schedule 21-NSTAR: Total Transfer Capability (TTC) methodology; Available Transfer Capability (ATC) methodology; Existing Transmission Commitment (ETC); Use of Transmission Reliability Margin (TRM); Use of Capacity Benefit Margin (CBM); and Use of Rollover Rights (ROR) in the calculation of ETC.

TTC and ATC are required to be calculated only for certain non-PTF internal paths over which Local Point-to-Point Service is provided under Schedule 21-NSTAR. TTC and ATC are not calculated by NSTAR for Local Network Service because ISO employs a market model for economic, security constrained dispatch of generation, and NSTAR does not require advance reservation for such network service.

2. Transmission Service in the New England Markets

Since the inception of the open access transmission tariff for New England, the process by which generation located inside New England supplies energy and/or capacity to the bulk electric system has differed from the Commission’s pro forma open access transmission tariff. The fundamental difference is that internal generation is dispatched in an economic, security constrained manner by the ISO rather than utilizing a system of physical rights, advance reservations and point-to-point transmission service. Through this process, internal generation provides offers that are utilized by the ISO in the Real-Time Energy Market dispatch software. This process provides the least-cost dispatch to satisfy Real-Time load on the system.

In addition to offers from generation within New England, entities may submit energy transactions that move into the New England Control Area, out of the New England Control Area or through the New

England Control Area. The Real-Time Energy Market clears these External Transactions based on forecast LMPs and the transfer capability of the associated external interfaces. With those External Transactions in place, the Real-Time Energy Market dispatches internal generation in an economic, security constrained manner to meet Real-Time load within the region.

The process for submitting External Transactions into the Real-Time Energy Market does not require an advance physical reservation for use of the PTF. In the event that the net of economic External Transactions is greater than the transfer capability of the associated external interface, the ExternalTransactions selected to flow are selected based on the rules specified in the Tariff. For any External Transactions that are confirmed to flow in Real-Time based on the economics of the system, a transmission reservation for RNS and Through-or-Out Service is created after-the-fact to satisfy the transparency needs of the market.

The process described above is applicable to the PTF within the New England Control Area, and non-PTF where utilized for Local Network Service by generation or load. However, NSTAR owns local transmission facilities over which an advance transmission service reservation for firm or non-firm transmission service may be required. On those facilities, Market Participants may obtain a transmission service reservation from NSTAR under Schedule 21-NSTAR prior to delivery of energy and/or capacity into the New England markets pursuant to Schedule 18, 20A or 20B of the Tariff. This document addresses the calculation of ATC and TTC for these non-PTF internal paths.

3. NSTAR Total Transfer Capability (TTC)

TTC is the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions. TTC for Schedule 21-NSTAR is calculated using NERC Standard MOD-029-1 Rated System Path Methodology and posted on the NSTAR OASIS site.

The TTC on NSTAR's Non-PTF that requires Local Point-to-Point Service reservations are relatively static values. NSTAR calculates the TTC for Posted Paths as the rating of the particular radial transmission path.NSTAR will calculate and post TTC on its OASIS site for all non-PTF Posted Paths that are eligible for Local Point-to-Point Service reservations. TTC is calculated as the transfer capability rating of the particular radial transmission path less the most limiting element within the PostedPath.

4. Capacity Benefit Margin (CBM)

CBM is defined as the amount of firm transmission transfer capability set aside by a Transmission Provider for use by the Load Serving Entities. The ISO does not set aside any CBM for use by the Load Serving Entities, because of the New England approach to capacity planning requirements in the ISO New England Operating Documents, and in any event, ISO's determination of CBM does not apply directly to the determination of ATC for Local Service. Load Serving Entities operating with the New England Control Area are required to arrange for their Capacity Requirements prior to the beginning of any given month in accordance with the Tariff, Section III.13.7.3.1 (Calculation of Capacity Requirement and Capacity Load Obligation). Load Serving Entities do not utilize CBM to ensure that their capacity needs are met; therefore, CBM is not applicable within the New England market design. Accordingly, for purposes of NSTAR's ATC calculation and because CBM for the New England Control Area is set to zero (0), NSTAR utilizes a zero (0) CBM value.

5. Transmission Reliability Margin (TRM)

TRM is the amount of transmission transfer capability set aside to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. It is used only for external interfaces under the New England market design. As NSTAR does not have any external interfaces, TRM for its non-PTF facilities is presently set to zero.

6. Existing Transmission Commitments

6.1 Existing Transmission Commitments, Firm (ETC_F)

ETC_F are confirmed Firm Local Point-To-Point Transmission Service reservations (PTP_F) plus any exercised rollover rights for Firm Point-To-Point Transmission Service reservations (ROR_F). There are no allowances necessary for Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$), grandfathered Transmission Service (GF_F), and other services, contracts or agreements (OS_F) to be considered in the ETC_Fcalculation.

6.2 Existing Transmission Commitments, Non-Firm (ETC_{NF})

ETC_{NF} are confirmed Non-Firm transmission reservations (PTP_{NF}). There are no allowances necessary for Non-Firm Network Integration Transmission Service ($NITS_{NF}$), Non-Firm grandfathered Transmission Service (GF_{NF}), or other services, contracts or agreements (OS_{NF}).

7. Calculation of ATC for NSTAR's Transmission System

NERC Standards MOD-001-1 – Available Transmission System Capability and MOD-029-1 – Rated

System Path Methodology define the required items to be identified when describing a Transmission Provider's ATC methodology. As a practical matter, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

Common practice is not to calculate or post firm and non-firm ATC values for the Non-PTF assets, as ATC is positive and listed as 9999. Transmission Customers are not restricted from reserving Firm or Non-Firm Point-to-Point Service on Non-PTF facilities.

As Real-Time approaches, the ISO utilizes the Real-Time Energy Market rules to determine which of the submitted energy transactions will be scheduled in the coming hour. Basically, the ATC of the non-PTF assets in the New England market is almost always positive. The ATC is equal to the amount of net energy and/or capacity transactions that the ISO will schedule on an interface for the designated hour. With this simplified version of ATC, there is no detailed algorithm to be described or posted other than: ATC equals TTC. Thus, for those non-PTF that serve as a path for NSTAR's Transmission Customers taking Local Point-to-Point Service, NSTAR has posted the ATC as 9999, consistent with industry practice. ATC on these paths varies depending on the time of day. However, it is posted with an ATC of "9999" to reflect the fact that there are no restrictions on these paths for commercial transactions.

7.1 Calculation of Schedule 21-NSTAR Firm ATC (ATC_F)

7.1.1 Calculation of ATC_F in the Planning Horizon (PH)

For purposes of this Attachment A, PH is any period before the Operating Horizon.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for TRM, CBM, ETC_F, $Postbacks_F$ and $counterflows_F$. As discussed above, TRM and CBM are zero. Firm Transmission Service under Schedule 21-NSTAR that is available in the PH includes: Yearly, Monthly, Weekly and Daily. $Postbacks_F$ and $counterflows_F$ of Schedule 21-NSTAR transmission reservations are not considered in the ATC calculation. Therefore, ATC_F in the PH is equal to the TTC minus ETC_F.

7.1.2 Calculation of ATC_F in the Operating Horizon (OH)

For purposes of this Attachment A, OH begins noon eastern prevailing time each day. At that time, the OH spans from noon through midnight of the next day for a total of 36 hours. As time progresses, the total hours remaining in the OH decrease until noon the following day when the OH is once again reset to

36 hours.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for ETC_F, CBM, TRM, $Postbacks_F$ and $counterflows_F$. As discussed above, TRM and CBM are zero. Daily Firm Transmission Service under Schedule 21-NSTAR is the only firm service offered in the OH. $Postbacks_F$ and $counterflows_F$ of Schedule 21-NSTAR transmission reservations are not considered in the ATC_F calculation. Therefore, ATC_F in the OH is equal to the TTC minus ETC_F.

7.1.3 Calculation of ATC_F in the Scheduling Horizon (SH)

Because Firm Schedule 21-NSTAR transmission service is not offered in the SH, ATC_F in the SH is zero.

7.2 Calculation of Schedule 21-NSTAR Non-Firm ATC (ATC_{NF})

7.2.1 Calculation of ATC_{NF} in the PH

ATC_{NF} is the capability for Non-Firm transmission reservations that remain after allowing for ETC_F, ETC_{NF}, scheduled CBM (CBM_S), unreleased TRM (TRM_U), Non-Firm Postbacks ($Postbacks_{NF}$) and Non-Firm counterflows ($counterflows_{NF}$). As discussed above, the TRM and CBM for Schedule 21-NSTAR are zero. ATC_{NF} available in the PH includes: Monthly, Weekly, Daily and Hourly. TRM_U, $Postbacks_{NF}$ and $counterflows_{NF}$ of Schedule 21-NSTAR transmission reservations are not considered in this calculation. Therefore, ATC_{NF} in the PH is equal to the TTC minus ETC_F and ETC_{NF}.

7.2.2 Calculation of ATC_{NF} in the OH

ATC_{NF} available in the OH includes: Daily and Hourly. As discussed above, the TRM and CBM for Schedule 21-NSTAR are zero. TRM_U, $counterflows_{NF}$ and ETC_{NF} of Schedule 21-NSTAR transmission reservations are not considered in this calculation. Therefore, ATC_{NF} in the OH is equal to the TTC minus ETC_F plus postbacks of PTP_F in the OH as PTP_{NF} ($Postbacks_{NF}$).

7.3 Negative ATC

As stated above, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available. As also stated above, NSTAR’s Non-PTF are primarily radial paths that provide transmission service to directly interconnected generators. It is possible that in the future a particular radial path may interconnect more nameplate capacity generation than the path’s TTC. For the local facilities modeled by ISO, and consistent with ISO’s economic, security-constrained dispatch methodology, the ISO will only dispatch an amount of generation

interconnected to such path so as not to incur a reliability or stability violation on the subject path. Therefore, ATC in the PH, OH and SH could become zero, but will never be negative.

8. Posting of Schedule 21-NSTAR ATC

8.1 Location of ATC Posting

ATC values are posted on the NSTAR OASIS site.

8.2 Updates to ATC

When any of the variables in the ATC equations change, the ATC values are recalculated and immediately posted.

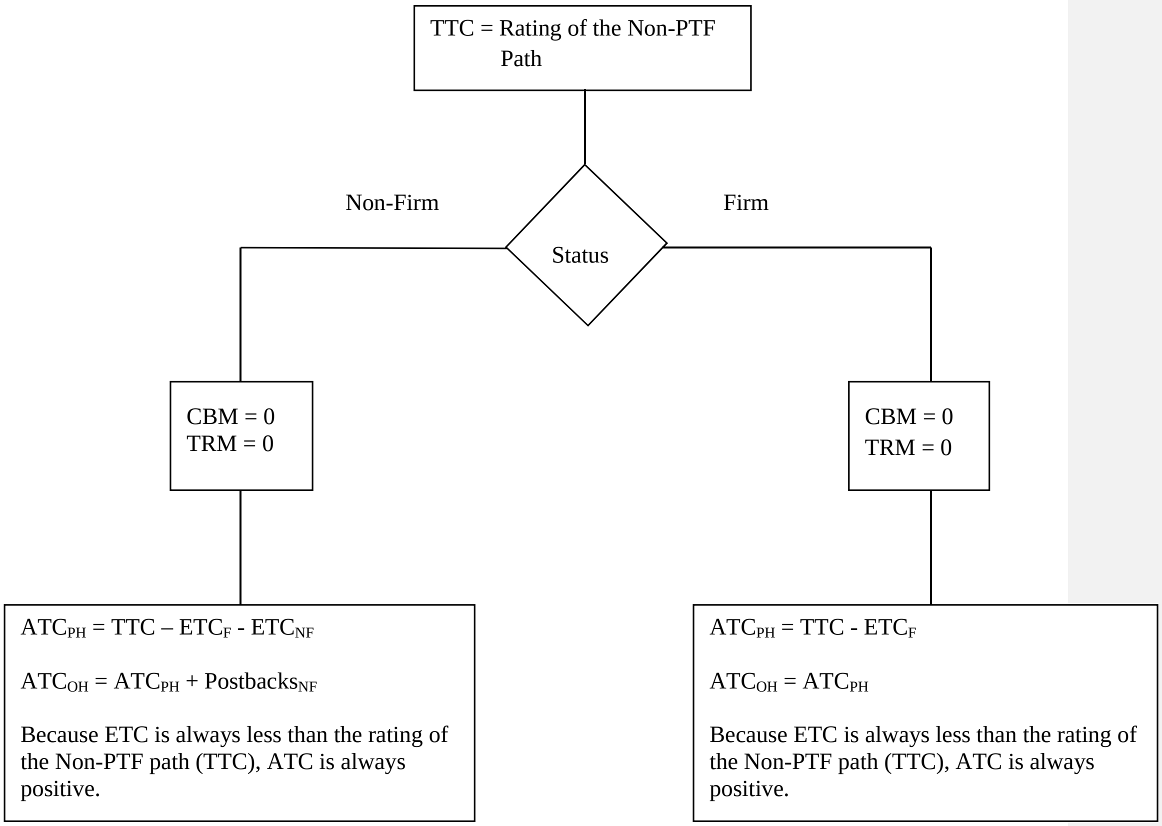
8.3 Coordination of ATC Calculations

NSTAR's Non-PTF has no external interfaces. Therefore, it is not necessary to coordinate the values.

8.4 Mathematical Algorithms

The mathematical algorithms for the calculation of ATC can be found on NSTAR's web site at http://www.nstar.com/business/rates_tariffs/open_access/docs/ATC_Algorithm-Sch_21.pdf

Non-PTF Transmission Path ATC Process Flow Diagram



ATTACHMENT B

METHODOLOGY FOR COMPLETING A SYSTEM IMPACT STUDY

When NSTAR determines on a non-discriminatory basis that a System Impact Study is needed because its Transmission System will be inadequate to accommodate a Completed Application for service, the following outlines the study methodology that NSTAR will employ to estimate the Transmission System impact of a Completed Application for Firm Local Point-To-Point Service, Network Integration Service and/or any costs associated with Direct Assignment Facilities and/or Local Network Upgrades that would be incurred in order to accommodate the service requested in the Completed Application.

1. System Impact will be estimated based on consideration of reliability requirements to:

- meet obligations under agreements that predate this Local Service Schedule;
- meet obligations of existing and pending Completed Application under this Local Service Schedule;
- maintain thermal, voltage and stability system performance within acceptable regional practices.

2. Guidelines and Principles followed by NSTAR: When performing the System Impact Study, NSTAR will apply the following, as amended and/or adopted from time to time.

- Good Utility Practice;
- Criteria, rules and reliability standards applicable to the New England Transmission System;
- NPCC criteria and guidelines; and
- NSTAR criteria and guidelines.

3. Transmission System Model Representation: The Transmission System model will be based on a library of load flow cases prepared by ISO for studies of the New England area. The models may include representations of other NPCC and neighboring systems. These load flow cases include individual system model representations provided by Transmission Owners and represent forecasted system conditions for up to ten (10) years into the future. This library of load flow cases is maintained and updated as appropriate by ISO, and is consistent with information filed under FERC Form 715. NSTAR will use system models that it deems appropriate for study of the Completed Application for service. Additional system models and operating conditions, including assumptions specific to a particular analysis, may be developed for conditions not available in the library of load flow cases. The system models may be modified, if necessary, to include additional system information on load, transfers and

configuration, as it becomes available.

4. System Conditions: Loading of all Transmission System elements shall be less than normal ratings for pre-contingency conditions and less than long-term emergency (LTE) ratings for post-contingency conditions. Post-contingency loading above LTE rating and less than short-term emergency (STE) rating may be allowed where demonstrated that loading can be reduced below the LTE rating within fifteen (15) minutes. Transmission System voltage shall be within the applicable design ratings of connected equipment for normal and emergency conditions. Normal and post-contingency voltages shall be in accordance with NSTAR and ISO standards.

5. Short Circuits: Transmission System short circuit currents shall be within the applicable equipment design ratings.

6. Study Analysis: System impact of the integration of new load will be evaluated to meet the requirements of design, identified in the guidelines and principles under Item 2 above, to provide sufficient transmission capability to maintain stability and to maintain thermal and voltage levels of lines and equipment within applicable limits. The same applies to the evaluation of Firm Point-To-Point Service when it has been determined that insufficient transfer capability is available and the Eligible Customer requests a System Impact Study be conducted.

7. Loss Evaluation: The impact of losses on the Transmission System will be taken into account in the System Impact Study to ensure Good Utility Practice in the design and operation of its system.

8. System Protection: Protection requirements will be evaluated by NSTAR in accordance with ISO, NPCC, and NSTAR criteria.

9. Approvals: NSTAR will conduct the System Impact Study to ensure compliance with its planning and design policies and practices. However, the actions to be taken by the Parties to implement the recommendations of the System Impact Study are subject to approval under the Tariff.

10. Study Scope and Reporting: The study will determine the impacts and identify changes required, if any, to NSTAR's existing Transmission System. NSTAR will provide the Eligible Customer with a written report of the physical interconnection alternative(s), required NSTAR system additions and/or modifications, if any, associated study grade cost estimates (+/- 25%) and the results of the analysis.

ATTACHMENT C

INDEX OF LOCAL POINT-TO-POINT SERVICE CUSTOMERS

Customer	Date of Service Agreement
AIG Trading Corporation	October 29, 1996
Altresco Pittsfield Light Plant	December 26, 1996
Aquila Power Company	February 26, 1997
Axia Energy, LP	June 20, 2001
Baltimore Gas & Electric Co.	January 14, 1997
Bangor Hydro-Electric Co.	October 1, 1996
Belmont Municipal Light Dept.	December 11, 1996
Central Vermont Public Service	January 3, 1997
Chicopee Municipal Light Dept.	October 2, 1996
CINERGY Capital and Trading, Inc.	January 1, 1998
CINERGY Operating Companies	December 1, 1997
Citizens Lehman Power Sales	November 6, 1996
Constellation Power Source, Inc.	July 11, 1997
Duke Energy Solutions, Inc.	March 19, 1999
DukeSolutions, Inc.	May 18, 1999
Edison Source	June 9, 1997
Electric Clearinghouse, Inc.	October 7, 1996
Entergy Nuclear Generation Company	April 10, 2003
Equitable Power Services Company	October 29, 1996
Green Mountain Power Corporation	January 10, 1997
HQ Energy Services (US) Inc.	February 8, 1999
LG&E Power Marketing, Inc.	October 8, 1996
Maine Public Service Company	September 30, 1996
Massachusetts Bay Transportation Authority	May 1, 1999
Massachusetts Municipal Wholesale Electric Co.	September 6, 1996
Merchant Energy Group of the Americas, Inc.	August 16, 1998
Mirant Canal, LLC	July 6, 1998
Mirant Americas Energy Marketing, LP	April 28, 2004
Montaup Electric Co.	October 15, 1996

Morgan Stanley Capital Group, Inc.	October 29, 1996
NEPOOL on Behalf of NEPOOL Participants	June 1, 1997
New England Power Company	December 30, 1996
New York State Gas & Electric Corp.	December 16, 1997
NorAm Energy Services	November 14, 1997
Northeast Energy Services, Inc.	June 17, 1997
NP Energy, Inc.	August 1, 1997
NRG Power Marketing, Inc.	January 1, 2001
NSTAR Electric Company	December 24, 1996
PECO Energy Power Team	January 3, 1997
Rainbow Energy Power Marketing	November 7, 1996
Reading Municipal Light Department	September 6, 1996
Sithe New England Holdings, LLC	January 3, 1998
Sonat Power Marketing, Inc.	November 14, 1997
Southern Energy Trading and Marketing, Inc.	March 10, 1997
Strategic Energy Ltd.	May 11, 1999
The Power Company of America	November 18, 1996
Town of Braintree Electric Light Dept.	September 6, 1996
Town of Hingham Municipal Light Plant	September 9, 1996
Town of Hull Municipal Light Plant	December 11, 1996
Trans Alta Energy Marketing	November 24, 1998
Trans Canada Power Corporation	January 27, 1997
Western Power Services, Inc.	December 24, 1996
Williams Energy Services Company	July 17, 1997
VTEC Energy, Inc.	March 24, 1998

ATTACHMENT D

ANNUAL TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirements for NSTAR ("the Company") will reflect the costs for its Transmission System, including costs attributable to those incurred by the Company in owning, leasing, maintaining and supporting the Transmission System net of revenues for transmission services provided under any other FERC accepted tariff or under any contract with other parties that provides reimbursement to the Company for transmission related services. Under no circumstances shall the Company's Local Network Service rates include costs that are charged through any other rate or tariff. The Transmission Revenue Requirements will be an annual calculation based on the estimated costs for its Transmission System during the Service Year.

The Company shall make an annual informational filing with the FERC on or before May 31 of each year which shall include a True-up of estimated costs and revenues, and actual costs and revenues for the preceding Service Year. Actual costs will be determined using data required to be reported annually in the FERC Form 1 and recorded on the Company's books in accordance with FERC's Uniform System of Accounts; unless the use of other data, such as subaccount balances, is specifically required by the provisions below, in which case an officer of the Company, shall certify that the development, accuracy and application of such other data is in accordance with the provisions of this Local Service Schedule. Such certification will be included with the annual informational filing along with adequate detail that supports the values contained within the True-up calculation. References to specific FERC Form 1 pages, line numbers and columns included in this Local Service Schedule are based on the 2006 Form 1 of the Company's predecessor entities. Subsequent FERC changes to Form 1 may be adopted to the extent they are consistent with the provisions and terms of this Local Service Schedule and not otherwise prohibited by FERC.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section II.1 of the OATT or the Local Service Schedule and as used herein have the following definitions:

A. ALLOCATION FACTORS

1. Transmission Wages and Salaries Allocation Factor shall equal the ratio of transmission-related direct wages and salaries including those of affiliated companies as reported in the

Company's annual FERC Form 1, page 354, line 21, column (b) to the Company's total direct wages and salaries including those of the affiliated companies as reported in the Company's FERC Form 1, page 354, line 28, column (b), and excluding administrative and general wages and salaries as reported in the Company's FERC Form 1, page 354, line 27, column (b).

2. Plant Allocation Factor shall equal the ratio of the sum of Transmission Plant, excluding HQ leases, plus Transmission Related Intangible and General Plant to Total Plant in Service excluding HQ Leases.

B. TERMS

Administrative and General Expense shall equal the expenses as reported in the Company's FERC Form 1, page 323, line 197, column (b), excluding Property Insurance included in FERC Account No. 924, Regulatory Commission Expense included in FERC Account No. 928, and Advertising Expense included in FERC Account No. 930.1 and excluding Merger-Related Costs included in FERC Account Nos. 920-935 (other than those in FERC Account Nos. 924, 928 and 930.1, which have already been excluded). The amount of Postretirement Benefits Other Than Pensions ("PBOP") expense in FERC Account No. 926 shall be separately stated as a footnote to the Company's FERC Form 1, page 323, line 187, column (b): Current Year and column (c): Previous Year.

Amortization of Gain on Reacquired Debt shall equal the amortization amount recorded in FERC Account No. 429.1.

Amortization of Loss on Reacquired Debt shall equal the expenses as recorded in FERC Account No. 428.1.

Amortization of Investment Tax Credits shall equal the credits as recorded in FERC Account No. 411.4.

Depreciation Expense for Transmission Plant shall equal the transmission expenses as recorded in FERC Account No. 403 as reported in the Company's annual FERC Form 1 page 336, line 7, column (f).

General Plant shall equal the gross plant balance as recorded in FERC Account Nos. 389-399.

General Plant Depreciation and Amortization Expense shall equal the general plant expenses as recorded in FERC Account Nos. 403 for depreciable items and 404 for items subject to amortization as reported in the Company's annual FERC Form 1, page 336, line 10, column (f).

General Plant Depreciation Reserve shall equal the general reserve balance as recorded in FERC Account No. 108 and reported in the Company's annual FERC Form 1, page 219, line 28, column (b).

General Plant Amortization Reserve shall equal the general reserve balance as recorded in FERC Account No. 111 and reported in the Company's annual FERC Form 1, page 200 in a footnote to line 14.

Hydro-Quebec DC Facilities (HQ Leases) shall equal the balance in capital leases as recorded in FERC Account Nos. 350-359 and FERC Account Nos. 389-399.

Intangible Plant shall equal the gross plant balance as recorded in FERC Account No. 303 as reported in the Company's annual FERC Form 1, page 205, line 4, column (g). The only allowable Intangible Plant for inclusion in the Local Service Schedule are software, patent or rights costs.

Intangible Plant Amortization Expense shall equal amortization expenses as recorded in FERC Account Nos. 404-405 as reported in the Company's annual FERC Form 1, page 336, line 1, column (f). The only allowable Intangible Plant Amortization Expense for inclusion in the Local Service Schedule is the amortization of software, patent or rights costs.

Intangible Plant Amortization Reserve shall equal the amortization reserve balance as recorded in FERC Account No. 111. The only allowable Intangible Plant Amortization Reserve for inclusion in the Local Service Schedule is that related to the amortization of software, patent or rights costs.

Merger-Related Costs shall equal NSTAR Electric's amortized merger-related costs as authorized by FERC or by state regulatory order.

Other Regulatory Assets/Liabilities - FAS 106 shall equal the net of the FAS 106 balance as recorded in FERC Account No. 182.3 and any FAS 106 balance as recorded in the FERC Account No. 254.

Other Regulatory Assets/Liabilities - FAS 109 shall equal the net of the FAS 109 asset and any FAS 109 balance liability.

Payroll Taxes shall equal those payroll expenses as recorded in the FERC Account No. 408.1.

Plant Held for Future Use shall equal the balance in FERC Account No. 105 that relates to land and land rights which have been purchased for future transmission use, or transmission related projects that were included in this account before January 1, 2007.

Prepayments shall equal the prepayment balance as recorded in FERC Account No. 165, plus any prepayment specifically related to the Company's Pension plans related to electric company operations recorded in FERC Account No. 182.3, Other Regulatory Assets.

Property Insurance shall equal the expenses as recorded in FERC Account No. 924.

Total Accumulated Deferred Income Taxes shall equal the net of the deferred tax balance as recorded in FERC Account Nos. 281-283 and 190 for those balances that are directly related to transmission, excluding those directly related to distribution or other businesses.

Total Gain on Reacquired Debt shall equal the gain as recorded in FERC Account No. 257.

Total Loss on Reacquired Debt shall equal the expenses as recorded in FERC Account No. 189.

Total Municipal Tax Expense shall equal the municipal tax expenses as recorded in FERC Account No. 408.1 as reported in the Company's annual FERC Form 1, page 263, line 10, column (i).

Total Plant in Service shall equal the total gross plant balance as recorded in FERC Account Nos. 301-399 excluding HQ Leases recorded in those accounts.

Total Transmission Depreciation Reserve shall equal the transmission reserve balance as recorded in FERC Account No. 108 as reported in the Company's annual FERC Form 1, page 219, line 25, column (b), excluding HQ-related amounts recorded in that account.

Transmission Depreciation Expense shall be the annual depreciation expense for transmission accounts computed using the following rates, as approved by FERC in Docket No. ER03-1274:

Account	Description	Rate

Account	Description	Rate
352	Structures and Improvements	2.19%
353	Station Equipment	2.53%
354	Towers and Fixtures	2.03%
355	Poles and Fixtures	2.25%
356	Overhead Conductors and Devices	2.19%
357	Underground Conduit	2.06%
358	Underground Conductors and Devices	2.15%
359	Roads and Trails	1.63%

Transmission Merger-Related Costs shall equal NSTAR Electric's amortized merger-related transmission costs as authorized by FERC.

Transmission Operation and Maintenance Expense shall equal all transmission-related expenses as recorded in FERC Account Nos. 560-564 and 566-576.5, and shall exclude; (i) all HQ HVDC expenses recorded in those accounts, and (ii) expenses billed to the Company by ISO-NE for Scheduling and Dispatch Service.

Transmission Plant shall equal the balance as recorded in FERC Account Nos. 350-359.1, adjusted to exclude the capital leases in the Hydro-Quebec DC Facilities (HQ Leases).

Transmission Plant Materials and Supplies shall equal the balance as assigned to transmission, as recorded in FERC Account No. 154 as reported in the Company's annual FERC Form 1, page 227, lines 5 and 8, column (c).

II. CALCULATION OF TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirement shall equal the sum of (A) Return and Associated Income Taxes, (B) Transmission Depreciation and Amortization Expense, (C) Transmission Related Amortization of Gain/Loss on Reacquired Debt, (D) Transmission Related Amortization of Investment Tax Credits, (E) Transmission Related Municipal Tax Expense, (F) Transmission Related Payroll Tax Expense, (G) Transmission Operation and Maintenance Expense, (H) Transmission Related Administrative and General Expenses, (I) Transmission Related Integrated Facilities Charges, minus (J) Transmission Support Revenue, plus (K) Transmission Support Expense, plus (L) Transmission-Related Expense from

Generators, minus (M) Transmission Rents Received from Electric Property, minus (N) Short-Term and Non-Firm Point-To-Point Service Revenues, minus (O) Regional Network Services (RNS) Revenues, minus (P) Through or Out Revenues, minus (Q) ISO-NE Scheduling and Dispatch Revenues.

A. Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate.

1. Transmission Investment Base

The Transmission Investment Base will be the year end balances of (a) Transmission Plant, plus (b) Transmission Related Intangible and General Plant, plus (c) Transmission Plant Held for Future Use, plus (d) 50 percent of Transmission Related Construction Work In Progress (CWIP), less (e) Transmission Related Depreciation and Amortization Reserve, less (f) Transmission Related Accumulated Deferred Taxes, less, (g) AFUDC Regulatory Liability, plus (h) Transmission Related Gain/Loss on Reacquired Debt, plus (i) Other Regulatory Assets/Liabilities, plus (j) Transmission Prepayments, plus (k) Transmission Materials and Supplies, plus (l) Transmission Related Cash Working Capital.

(a) Transmission Plant will equal the balance of the investment in Transmission Plant. This value excludes the capital leases in the Hydro-Quebec DC Facilities (HQ Leases).

(b) Transmission Related Intangible and General Plant shall equal the sum of the balance of investment in Intangible Plant and General Plant multiplied by the Transmission Wages and Salaries Allocation Factor.

(c) Transmission Plant Held for Future Use shall equal the land and land rights portion of the balance of Transmission-related Plant Held for Future Use (FERC Account No. 105) plus the non-land Plant Held for Future Use related to projects that were included in Account No. 105 prior to January 1, 2007 to the extent such non-land plant has not been closed to Plant In Service; such balances to be provided in conformance with the FERC Uniform System of Accounts, Instruction E, Account No. 105 which requires that "…property included in this account shall be classified according to detail accounts (301-399)…and shall be maintained in such detail as though the property were in service."

(d) 50 Percent of Transmission Related Construction Work in Process (CWIP) shall equal the balance of Transmission related investment in FERC Account 107 multiplied by 50%, subject to any exclusions pursuant to the provisions of Section 4.1 of this Local Service Schedule.

(e) Transmission Related Depreciation and Amortization Reserve shall equal the balance of Total Transmission Depreciation Reserve as reported in the Company's annual FERC Form 1, page 219 line 25, column (b), plus the balance of Transmission Related Intangible Plant Amortization Reserve, Transmission Related General Plant Depreciation Reserve and Transmission Related General Plant Amortization Reserve. Transmission Related Intangible Plant Amortization Reserve, Transmission Related General Plant Depreciation Reserve and Transmission Related General Plant Amortization Reserve shall equal the product of (i) the sum of the Intangible Plant Amortization Reserve, General Plant Depreciation Reserve and General Plant Amortization Reserve and (ii) the Transmission Wages and Salaries Allocation Factor. The Total Transmission Depreciation Reserve balance excludes any amounts related to the capital leases in the Hydro-Quebec DC Facilities (HQ Leases).

(f) Transmission Related Accumulated Deferred Taxes shall equal the electric balance of Total Accumulated Deferred Income Taxes (for those balances that are directly related to transmission, plus the balances not directly related to other businesses), with the remaining accumulated deferred taxes not directly related to other businesses being allocated on the same basis used for the related rate base assets.

(g) AFUDC Regulatory Liability shall equal 50% of the capitalized AFUDC booked on transmission projects as recorded in FERC Account No. 254.

(h) Transmission Related Gain/Loss on Reacquired Debt shall equal the electric balance of Total Gain/Loss on Reacquired Debt multiplied by the Plant Allocation Factor.

(i) Other Transmission Related Regulatory Assets/Liabilities shall equal the electric balance of any deferred rate recovery of FAS 106 expenses multiplied by the Transmission Wages and Salaries Allocation Factor, plus the electric balance of FAS 109 multiplied by the Plant Allocation Factor.

(j) Transmission Prepayments shall equal the electric balance of Prepayments multiplied by the Transmission Wages and Salaries Allocation Factor.

(k) Transmission Materials and Supplies shall equal the electric balance of Transmission Plant Materials and Supplies.

(l) Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of the Transmission Operation and Maintenance Expense included in Section II.G, Transmission Related Administrative and General Expenses included in Section II.H, and Transmission Support Expenses included in Section II.K.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) the Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital for Service Years ending before January 1, 2013 will be calculated based 70% upon the capital structure at the end of each year and 30% upon a pro-forma capital structure consisting of 50% debt, 0% preferred, and 50% common equity; thereafter the pro-forma capital structure will be the same as the actual capital structure, and will equal the sum of (i), (ii) and (iii) below. Notwithstanding the foregoing, for Service Years ending before January 1, 2013, NSTAR's Weighted Cost of Capital will be the lower of the blended rate as calculated herein or the actual rate.

(i) the long-term debt component, which equals the product of: the actual weighted average embedded cost to maturity of the long-term debt then outstanding; and the sum of (a) the ratio that long-term debt is to the total capital multiplied by 70%, plus (b) 50% pro-forma capital structure multiplied by 30%.

(ii) the preferred component shall be the product of: the embedded cost of preferred stock outstanding at the end of each year; and the sum of (a) the ratio that preferred stock is to the total capital multiplied by 70%, plus (b) 0% pro-forma capital structure multiplied by 30%.

(iii) the return on equity component shall be the product of: the allowed ROE of the common equity; and the sum of (a) the ratio that common equity is to the total capital multiplied by 70%, plus (b) 50% pro-forma capital structure multiplied by 30%. The allowed ROE shall be 10.57%, plus any additional incentive ROE adders as may be applied to specific investment approved by the Commission pursuant to Order No. 679, provided that the total ROE for any project, including any such ROE incentives, shall be capped by the top of the applicable zone of reasonableness determined by FERC for the relevant period. The allowed ROE shall be subject to revision at any time by unilateral filing by NSTAR under Section 205 of the FPA or by such Section 205 filing by NSTAR on a joint basis with other New England transmission owners. In either case, the revised ROE shall become effective no later than sixty days after the filing in accordance with the provisions of the FPA and also subject to any suspension or refund condition which the Commission may order pursuant to its authority under that Section. Any filing made by NSTAR to revise the ROE in compliance with a Commission order shall become effective as of the date specified in such order and shall raise no issue regarding this Local Service Schedule other than the compliance with the Commission order. The allowed ROE is also subject to revision pursuant to the authority of the Commission under Sections 205 and 206 of the FPA.

(b) Federal Income Tax shall equal

$$\frac{(A+[(C+B)/D])(FT)}{1 - FT}$$

where FT is the Federal Income Tax Rate and A is the weighted return on equity component, including preferred, as determined in Sections II.A.2.(a)(ii) and (iii) above, B is Transmission Related Amortization of Investment Tax Credits, as determined in Section II.D below, C is the equity AFUDC component of Transmission Depreciation and Amortization Expense, as defined in Section II.B below, and D is Transmission Investment Base, as determined in Section II.A.1 above.

(c) State Income Tax shall equal

$$\underline{(A+[(C+B)/D] + \text{Federal Income Tax})(ST)}$$

1 – ST

where ST is the State Income Tax Rate, A is the weighted return on equity component, including preferred, determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section II.D below, C is the equity AFUDC component of Transmission Depreciation and Amortization Expense, as defined in Section II.B below, D is the Transmission Investment Base, as determined in II.A.1 above and Federal Income Tax is the rate determined in Section II.A.2.(b) above.

B. Transmission Depreciation and Amortization Expense shall equal the sum of (i) the Depreciation Expense for Transmission Plant and (ii) an allocation of Intangible Plant Amortization Expense and General Plant Depreciation Expense, which is calculated by multiplying the sum of (a) Intangible Plant Amortization Expense and (b) General Plant Depreciation Expenses by the Transmission Wages and Salaries Allocation Factor; less the Amortization of AFUDC Regulatory Credit as recorded in FERC Account No. 407.4.

C. Transmission Related Amortization of Gain/Loss on Reacquired Debt shall equal the electric Amortization of Gain/Loss on Reacquired Debt multiplied by the Plant Allocation Factor.

D. Transmission Related Amortization of Investment Tax Credits shall equal the electric Amortization of Investment Tax Credits multiplied by the Plant Allocation Factor.

E. Transmission Related Municipal Tax Expense shall equal the total electric municipal tax expense reported in the Company's FERC Form 1, page 263, Local Real Estate and Personal Property Taxes, column (i), multiplied by the Plant Allocation Factor.

F. Transmission Related Payroll Tax Expense shall equal the total electric payroll tax expense reported in the Company's FERC Form 1, page 263, Service Company Allocations and Capitalization, column (i), multiplied by the Transmission Wages and Salaries Allocation Factor.

G. Transmission Operation and Maintenance Expense shall equal the Transmission Operation and Maintenance Expenses in Section I.B above.

H. Transmission Related Administrative and General Expenses shall equal the sum of the (1)

Administrative and General Expense multiplied by the Transmission Wages and Salaries Allocation Factor, (2) Property Insurance included in FERC Account No. 924, line 156 multiplied by the Transmission Plant Allocation Factor, ~~and~~ (3) expenses included in Account No. 928 (excluding Merger-Related Costs included in Account No. 928), line 160 related to (i) transmission related FERC Assessments, plus (ii) any other Federal and State transmission related expenses or assessments, plus (iii) the cost of any independent audit requested by the Mass AG as the representative for NSTAR's retail customers and (4) Transmission Merger-Related Costs. The amount of PBOP expense shall be separately stated. NSTAR commits to adhere to: (i) the Commission's PBOP policy as expressed in the Commission's December 17, 1992, Statement of Policy in Docket No. PL93-1-000, as the Commission may amend that policy from time to time in the future; and (ii) the provisions of Financial Accounting Statement 106, Employers' Accounting for Postretirement Benefits Other Than Pensions.

I. Transmission Related Integrated Facilities Charges shall equal the transmission payments to Affiliates for use of the integrated transmission facilities of those Affiliates included in FERC Account No. 565.

J. Transmission Support Revenues shall equal the revenue received for transmission support included or includable in FERC Account Nos. 454 and 456 but excluding any revenue received for use of the Company's entitlement in the Hydro-Quebec Facilities.

K. Transmission Support Expense shall equal the expense paid by the Company for transmission support included in FERC Account No. 565, but excluding expenses for the Hydro-Quebec DC Facilities.

L. Transmission-Related Expense from Generators shall equal the expenses from generators that are reflected in a filing made by the Company with the Commission under Section 205 of the Federal Power Act and accepted by the Commission for recovery under the Local Service Schedule and included or includable in FERC Account No. 565.

M. Transmission Rents Received from Electric Property shall equal any FERC Account Nos. 454 and 456 Rents from Electric Property, associated with Transmission Plant but not reflected as a credit in Transmission Support Revenues in Section II.J.

N. Short-Term and Non-Firm Point-to-Point Service Revenues shall equal the applicable wheeling revenues received for Local Point-To-Point Service provided under this Local Service Schedule, including the transmission component of the Company’s Third-Party Sales, as recorded in FERC Account Nos. 447 and 456.1.

O. Regional Network Services (RNS) Revenues shall equal the Company’s RNS revenues pursuant to the Tariff, as included or includable in FERC Account Nos. 454, 456 and 456.1 but excluding any incremental revenues associated with FERC-approved adders for RTO participation and new investment.

P. Through or Out Revenues shall equal the distribution of revenues received by the Company for Through or Out Service pursuant to the Tariff as included or includable in FERC Account Nos. 454 and 456.1.

Q. ISO-NE Scheduling and Dispatch Revenues shall be the amount of revenues received by the Company from ISO-NE for scheduling and dispatch services pursuant to the Tariff as included or includable in FERC Account Nos. 454, 456 and 456.1.

ATTACHMENT E

INDEX OF LOCAL NETWORK SERVICE CUSTOMERS

Customer	Date of Service Agreement
ANP Blackstone Energy Company	October 1, 2000
Entergy Nuclear Generation Company	September 1, 1999
New England Power Company	September 6, 1996
NSTAR Electric Company	December 24, 1996
Sithe New Boston LLC	September 1, 1998
Sithe Framingham LLC	September 1, 1998
Sithe Mystic LLC	September 1, 1998
Sithe Edgar LLC	September 1, 1998
Sithe West Medway LLC	September 1, 1998
Town of Braintree Municipal Light Dept.	March 1, 1997
Town of Concord Municipal Light Plant	June 21, 2002
Town of Hingham Municipal Light Plant	March 1, 1997
Town of Hull Municipal Light Plant	March 1, 1997
Town of Norwood Municipal Light Dept.	September 6, 1996
Town of Reading Municipal Light Plant	March 1, 1997
Town of Wellesley Municipal Light Plant	June 21, 2002

ATTACHMENT F

FORMULA RATE TEMPLATE

NSTAR Electric Company

Annual Local Network Service Revenue Requirement

Service Year Ended December 31, xxxx

This template does not change the other provisions of this Schedule 21. The template is not a substitute for Schedule 21 language. If an inconsistency between the Schedule 21 language and the template arises, the Schedule 21 language is controlling. The template is illustrative and the actual true-up filing as made from time to time may include format changes or reflect non-material changes required by the Uniform System of Accounts.

Sheet 1

	(a)	(b)	(c)	(d)
Line	**Description**	**Section**	**Amount**	**Reference**
1	**Investment Base**	II.A.1		
2	Transmission Plant	II.A.1.a	$ -	Sheet 3, Line 1, Col (f)
3	Transmission Related Intangible & General Plant	II.A.1.b	-	Sheet 3, Line 4, Col (f)
4	Transmission Plant Held for Future Use	II.A.1.c	-	Sheet 3, Line 5, Col (f)
5	Transmission Related Construction Work in Progress	II.A.1.d	-	Sheet 3, Line 6, Col (f)
6	Total Plant		-	Sum Lines 2 thru 5
7	Trans Related Depreciation and Amortization Reserve	II.A.1.e	-	Sheet 3, Line 12, Col (f)
8	Transmission Related Accumulated Deferred Taxes	II.A.1.f	-	Sheet 3, Line 20, Col (f)
9	AFUDC Regulatory Liability	II.A.1.g	-	Sheet 3, Line 21, Col (f)
10	Total Net Plant		-	Sum Lines 6 thru 9
11	Transmission Related Gain/Loss on Reacquired Debt	II.A.1.h	-	Sheet 3, Line 22, Col (f)
12	Other Trans Related Regulatory Assets/Liabilities	II.A.1.i	-	Sheet 3, Line 28, Col (f)
13	Transmission Prepayments	II.A.1.j	-	Sheet 3, Line 29, Col (f)
14	Transmission Materials & Supplies	II.A.1.k	-	Sheet 3, Line 30, Col (f)
15	Transmission Related Cash Working Capital	II.A.1.l	-	Sheet 3, Line 35, Col (f)
16	**Total Investment Base**		$ -	Sum Lines 10 thru 15
17	**Revenue Requirement**			
18	Investment Return and Income Taxes	II.A.2	$ -	Sheet 2, Line 39, Col (c)
19	Transmission Depreciation and Amortization Expense	II.B	-	Sheet 4, Line 7, Col (f)
20	Amortization of Gain/Loss on Reacquired Debt	II.C	-	Sheet 4, Line 8, Col (f)
21	Transmission Related Amort. of Investment Tax Credits	II.D	-	Sheet 4, Line 9, Col (f)
22	Transmission Related Municipal Tax Expense	II.E	-	Sheet 4, Line 10, Col (f)
23	Transmission Related Payroll Tax Expense	II.F	-	Sheet 4, Line 11, Col (f)
24	Transmission Operation & Maintenance Expense	II.G	-	Sheet 4, Line 30, Col (f)
25	Trans Related Administrative and General Expense	II.H	-	Sheet 4, Line 44~~42~~, Col (f)
26	Transmission Related Integrated Facilities Charges	II.I	-	Sheet 5, Line 10, Col (e)
27	Transmission Support Revenues	II.J	-	Sheet 5, Line 15, Col (e)
28	Transmission Support Expense	II.K	-	Sheet 5, Line 20, Col (e)
29	Transmission Related Expense from Generators	II.L	-	Sheet 5, Line 23, Col (e)
30	Transmission Rents Received from Electric Property	II.M	-	Sheet 5, Line 28, Col (e)
31	Short-Term and Non-Firm P-T-P Service Revenues	II.N	-	Sheet 5, Line 31, Col (e)
32	Regional Network Services (RNS) Revenues	II.O	-	Sheet 5, Line 36, Col (e)
33	Through or Out Revenues	II.P	-	Sheet 5, Line 39, Col (e)
34	ISO-NE Scheduling and Dispatch Revenues	II.Q	-	Sheet 5, Line 43, Col (e)
35	**Total LNS Revenue Requirement**		$ -	Sum Lines 18 thru 34
36	Wholesale LNS Revenues Received:			
37	Item # 1		-	
38	Item #2		-	

39	Last Item	-	
40	Total Wholesale LNS Revenue	$ -	Sum Lines 37 thru 39
41	**Total Retail LNS Revenue Requirement**	**$ -**	Line 35 - Line 40
42	Average 12 CP		
43	Sum of Monthly Peaks (kw)	-	FF1: 400.17(b)
44	Average Peak	-	Line 43 / 12
45	Annual Rate per kw	$ -	Line 35 / Line 44
46	Monthly Rate per kw	$ -	Line 45 / 12
47	Daily Rate per kw	$ -	Line 45 / 365

NSTAR Electric Company

Investment Return and Income Taxes

Service Year Ended December 31, xxxx

Sheet 2

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		Tariff		**Capitalization**		**Weighted**	**Equity**	
Line	**Description**	**Section**	**Balance**	**Ratio ***	**Cost ***	**Cost ***	**Cost**	**Reference**
1	**Weighted Cost of Capital**	II.A.2.a						
2	Long Term Debt	II.A.2.a.i	$ -		0.0000%	0.0000%		FF1: Page 112.24(c)
3	Preferred Stock	II.A.2.a.ii	-		0.0000%	0.0000%	0.0000%	FF1: Page 112.3(c)
4	Common Equity	II.A.2.a.iii	-		0.0000%	0.0000%	0.0000%	FF1: Page 112.16(c) - Line 3(c)
5	Total		$ -			0.0000%	0.0000%	Sum Lines 2 thru 4
6	**Investment Return**	II.A.2						
7	Total Investment Base		$ -					Sheet 1, Line 16, Col (c)
8	Weighted Cost of Capital		0.0000%					Line 5, Col (f)
9	Total Return on Investment		$ -					Line 7 * Line 8
10	**Federal Income Tax**	II.A.2.b						
11	A = Equity Cost		0.0000%					Line 5, Col (g)
12	B = Transmission Amortization of ITC		$ -					Sheet 1, Line 21, Col (c)
13	C = Equity AFUDC		-					FF1: Page 117.38
14	Total B + C		-					Line 12 + Line 13
15	D = Investment Base		-					Line 7
16	(B + C) / D		0.00%					Line 14 / Line 15
17	(A + [(C + B) / D]		0.00%					Line 11 + Line 16
18	FT = Federal Income Tax Rate		35.00%					Federal corporate tax rate
19	1 - FT		65.00%					1 - Line 18
20	Federal Tax Factor		0.00000%					Line 17 * Line 18 / Line 19
21	Total Federal Income Taxes		$ -					Line 15 * Line 20
22	**State Income Tax**	II.A.2.c						
23	A = Equity Cost		0.0000%					Line 5, Col (g)
24	B = Transmission Amortization of ITC		$ -					Sheet 1, Line 21, Col (c)
25	C = Equity AFUDC		-					
26	Total B + C		-					Line 24 + Line 25
27	D = Investment Base		-					Line 7
28	(B + C) / D		0.00%					Line 26 / Line 27
29	(A + [(C + B) / D]		0.00%					Line 23 + Line 28
30	ST = State Income Tax Rate		6.50%					Massachusetts corporate tax rate
31	1 - ST		93.50%					1 - Line 30
32	Federal Tax Factor		0.00000%					Line 23
33	State Tax Factor		0.00000%					(Line 29 + Line 32) * Line 30 / Line 31
34	Total State Income Taxes		$ -					Line 27 * Line 33
35	**Investment Return and Income Taxes**	II.A.2						
36	Return on Investment		$ -					Line 9

37	Federal Income Taxes	-	Line 21
38	State Income Taxes	-	Line 34
	Total Return and Income		
39	**Taxes**	**$ -**	Sum Lines 36 thru 38

* Note that weighting and cost are determined on Sheet 7

NSTAR Electric Company

Investment Base

Service Year Ended December 31, xxxx

Sheet 3

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Tariff				**Allocations**	
						LNS	
Line	**Description**	**Section**	**Total**	**Allocator**	**Factor**	**Amount**	**Reference**
1	**Transmission Plant**	II.A.1.a	$ -	Direct	100.0000%	-	FF1: Page 207.58(g)
2	General Plant		-	W&S	0.0000%	-	FF1: Page 207.99(g)
3	Intangible Plant		-	W&S	0.0000%	-	FF1: Page 205.5(g)
4	**Total Intangible & General Plant**	II.A.1.b	-			-	Sum Lines 2 thru 3
5	**Transmission Plant Held for Future Use**	II.A.1.c	-	Direct	100.0000%	-	FF1: Page 214.10&.23(d)
6	**Transmission Related CWIP**	II.A.1.d	-	CWIP	50.0000%	-	FF1: Page 216(b) Trans only
7	**Transmission Related Dep & Amort Reserve**	II.A.1.e					
8	Transmission Accumulated Depreciation		-	Direct	100.0000%	-	FF1: Page 219.25(b)
9	General Plant Accumulated Depreciation		-	W&S	0.0000%	-	FF1: Page 219.28(b)
10	General Plant Accumulated Amortization		-	W&S	0.0000%	-	FF1: Page 200.21(c) Footnote
11	Intangible Plant Accumulated Amortization		-	W&S	0.0000%	-	FF1: Page 200.21(c) Footnote
12	Total Transmission Related Depreciation Reserve		-			-	Sum Lines 8 thru 11
13	**Transmission Accumulated Deferred Taxes**	II.A.1.f					
14	Accumulated Deferred Taxes (190)		-		0.0000%	-	Sheet 8, Line 5, col (d)
15	Accumulated Deferred Income Taxes (281)		-			-	FF1: Page 113.62(c)
16	Accumulated Deferred Taxes - Property (282)		-				FF1: Page 275.9(k)
17	Less Transition Property		-				FF1: Page 275.4(k)
18	Net Acc. Def. Income Taxes - Other Property (282)		-	Plant	0.0000%	-	Sum Lines 16 thru 17
19	Accumulated Deferred Income Taxes - Other (283)		-		0.0000%	-	Sheet 8, Line 10, col (d)
20	Total					-	Sum Lines 17 thru 19
21	**AFUDC Regulatory Liability**	II.A.1.g	-	Direct	100.00%	-	FF1: Page 278.6(f)
22	**Gain/Loss on Reacquired Debt**	II.A.1.h	-	Plant	0.0000%	-	FF1: Page 111.81(c)+113.61(c)
23	**Other Regulatory Assets**	II.A.1.i					
24	FAS 106 (182.3 & 254)		-	W&S	0.0000%	-	FF1: Page 232.1.39(f)+278.(f)
25	FAS 109 (182.3 & 254)		-				FF1: Page 232.1.29(f)
26	Less FAS 109 - Liability (182.3 & 254)		-				FF1: Page 278.2(f)
27	Net FAS 109 (182.3 & 254)		-	Plant	0.0000%	-	Sum Lines 25 thru 26
28	Total Other Regulatory Assets		-			-	Line 24 + line 27

29	**Prepayments**	II.A.1.j	-	W&S	0.0000%	-	FF1: Page 111.57(c)+ 232.2.8(f)
30	**Transmission Materials & Supplies**	II.A.1.k	-	Direct	100.0000%	-	FF1: Page 227.8(c)+227.5(c) Trans
31	**Cash Working Capital**	II.A.1.l					
32	Operation & Maintenance Expense		-	WC	12.50%	-	Sheet 1, Line 24, col (c)
33	Administrative & General Expense		-	WC	12.50%	-	Sheet 1, Line 25, col (c)
34	Transmission Support Expenses		-	WC	12.50%	-	Sheet 1, Line 28, col (c)
35	Total Cash Working Capital		-			-	Sum Lines 32 thru 33

		Allocation	
36	**Description**	**Factor**	**Reference**
37	Direct Allocation (Direct)	100.0000%	
38	Wages & Salary (W&S)	0.0000%	Sheet 6, Line 6(c)
39	Plant Allocation (Plant)	0.0000%	Sheet 6, Line 14(c)
40	Construction Work in Progress Allocation (CWIP)	50.0000%	Sheet 6, Line 15(c)
41	Cash Working Capital (WC)	12.50%	Tariff Section II.A.1.l

NSTAR Electric Company
Transmission Expenses
Service Year Ended December 31, xxxx
Sheet 4

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Tariff		**Allocations**			
Line	**Description**	**Section**	**Total**	**Allocator**	**Factor**	**LNS Amount**	**Reference**
1	**Transmission Depreciation Expense**	II.B					
2	Transmission Depreciation	II.B.i		Direct	100.00%	$ -	FF1: Page 336.7(f)
3	General Plant Depreciation and Amortization	II.B.ii		W&S	0.00%	-	FF1: Page 336.10(f)
4	Amortization of Transmission Related Intangible Plant			W&S	0.00%	-	FF1: Page 336.1(f)
5	Amortization of AFUDC Regulatory Credit		-			-	FF1: Page 278.6(d) (amort)
6	Net Amortization of Transmission Related Intangible Plant		-			-	Sum Lines 4 and 5
7	Total Transmission Depreciation Expense		$ -			$ -	Sum Lines 2, 3 and 6
8	**Amortization of Gain/Loss on Reacquired Debt**	II.C		Plant	0.00%	$ -	FF1: Page 117.64c
9	**Transmission Related Amortization of ITC**	II.D		Plant	0.00%	$ -	FF1: Page 114.19(c)
10	**Transmission Related Municipal Tax Expense**	II.E		Plant	0.00%	$ -	FF1: Page 263.5(i)
11	**Transmission Related Payroll Tax Expense**	II.F		W&S	0.00%	$ -	FF1: Page 263.8i
12	**Transmission Operation and Maintenance Expense**	II.G					
13	Operation Supervision & Engineering (560)			Direct	100.00%	$ -	FF1: Page 321.83(b)
14	Load Dispatching (561)		-	Internal Costs		-	FF1: Page 321.83(b)
15	Load Dispatch - Reliability (561.1)		-	Internal Costs		-	FF1: Page 321.85(b) footnote
16	Load Dispatch-Mon and Oper Trans System (561.2)		-	Internal Costs		-	FF1: Page 321.86(b) footnote
17	Load Dispatch-Trans Service and Scheduling (561.3)		-	Internal Costs		-	FF1: Page 321.87(b) footnote
18	Scheduling, System Control and Dispatch Services (561.4)		-	Internal Costs		-	FF1: Page 321.88(b) footnote

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19	Reliability, Planning and Standards Development (561.5)		-	Internal Costs		-	FF1: Page 321.89(b)
20	Transmission Service Studies (561.6)		-	Internal Costs		-	FF1: Page 321.90(b)
21	Generation Interconnection Studies (561.7)		-	Internal Costs		-	FF1: Page 321.91(b)
22	Reliability, Planning and Standards Development (561.8)		-	Internal Costs		-	FF1: Page 321.92(b) footnote
23	Station Expenses (562)		-	Direct	100.00%	-	FF1: Page 321.93(b)
24	Overhead Lines Expenses (563)		-	Direct	100.00%	-	FF1: Page 321.94(b)
25	Underground Lines Expenses (564)		-	Direct	100.00%	-	FF1: Page 321.95(b)
26	Miscellaneous Transmission Expenses (566)		-	Direct	100.00%	-	FF1: Page 321.97(b)
27	Rents (567)		-	Direct	0.00%	-	Sheet 5, Line 7, col (d)
28	Transmission Maintenance (568 - 573)		-	Direct	100.00%	-	FF1: Ppage 321.111(b)
29	Regional Market Expense (575)		-	Internal Costs	0.00%	-	FF1: Ppage 322.131(b)
30	Total Transmission O&M Expense		$ -			$ -	Sum Lines 13 thru 28
31	**Transmission Related A&G Expenses**	II.H					
32	Administrative and General Expenses			$0			FF1: Page 323.197(b)
33	Property Insurance (924)		-				FF1: Page 323.185(b)
34	Employee Pension and Benefits (926)		-				FF1: Page 323.187(b)
35	Regulatory Commission Expense (928)		-				FF1: Page 323.189(b)
36	General Advertising Expense (930.1)		-				FF1: Page 323.191(b)
37	Merger Related Costs		-				FF1: Page 320 FN
~~37~~38	Sub-Total		-	W&S	0.00%	-	Sum Lines 32 thru ~~36~~ 37
~~38~~39	Property Insurance (924)	II.H.2	-	Plant	0.00%	-	Line 33
~~39~~40	Employee Pension and Benefits (926) - Note 1	II.H.1	-	W&S	0.00%	-	Line 34
~~40~~41	Regulatory Commission Expense (928)	II.H.3	-	Footnote	0.00%	-	Line ~~57~~ 59
~~41~~42	General Advertising Expense (930.1)	II.H	-		0.00%	-	Line 36
43	Transmission Merger Related Costs		-	Direct	100.00%	-	FF1: Page 320 FN
44~~42~~	Total Transmission Related A&G Expenses		$ -			$ -	Sum Lines ~~37~~ 39 thru 44~~1~~3
45~~43~~	Regulatory Commission Expense (928)	II.H.3					
46~~44~~	DPU - General Assessment		$ -		0.00%	$ -	FF1: Page 350.1 (d)
47~~45~~	DPU - Appropriation Account		-		0.00%	-	FF1: Page 350.2 (d)
48~~46~~	DPU - AGO Assessment #1		-		0.00%	-	FF1: Page 350.3 (d)

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Line	Description	Ref.	Amount	Allocator	Factor	Allocated	Source
49~~47~~	DPU - AGO Assessment #2		-		0.00%	-	FF1: Page 350.4 (d)
50~~48~~	DPU - Outage Reporting Assessment		-		0.00%	-	FF1: Page 350.5 (d)
51~~49~~	DPU - Manhole Cover Assessment		-		0.00%	-	FF1: Page 350.6 (d)
52~~50~~	DPU - Stray Voltage Assessment		-		0.00%	-	FF1: Page 350.7 (d)
53~~51~~	MA Emergency Management Agency		-		0.00%	-	FF1: Page 350.8 (d)
54~~52~~	FERC Assessment		-	Direct	100.00%	-	FF1: Page 350.9 (d)
55~~53~~	FER LICAP Docket		-	Direct	100.00%	-	FF1: Page 350.10 (d)
56~~54~~	FERC RMR Docket		-	Direct	100.00%	-	FF1: Page 350.11 (d)
57~~55~~	FERC Docket ER07-549, Including cost of audit		-	Direct	100.00%	-	FF1: Page 350.12 (d)
58~~56~~	DPU Regulatory Proceeding Costs 05-85		-		0.00%	-	FF1: Page 350.13 (d)
59~~57~~	Total Regulatory Commission Expenses	II.H.3	-		0.00%	-	Sum Lines ~~44~~ 46 thru ~~56~~ 58

~~58~~	**Description**	**Allocation Factor**	**Reference**
60~~59~~	Direct Allocation (Direct)	100.0000%	
61~~60~~	Wages & Salaries Allocation (W&S)	0.0000%	Sheet 6, Line 6(c)
62~~61~~	Plant Allocation (Plant)	0.0000%	Sheet 6, Line 14(c)

63~~62~~ **Note 1**

64~~63~~ Included in the Employee Pension and Benefits Expenses are costs related to Post Retirement Benefits other than Pension (PBOP). PBOP costs are determined

65 by an independent actuary as required by FASB 106. The PBOP expense included in Account 926 for 20xx was $xx,xxx,xxx as compared to $xx,xxx,xxx in the prior year;

66~~64~~ as shown

67~~65~~ on the FF1, Page 323, footnote. Applying the labor allocator to the total PBOP expense results in $x,xxx,xxx of PBOP expense being recovered through the LNS Tariff

68~~66~~ in 20xx as compared to $x,xxx,xxx in the prior year.

NSTAR Electric Company
Support Expense & Revenue Detail
Service Year Ended December 31, xxxx
Sheet 5

	(a)	(b)	(c)	(d)	(e)
		Tariff			
Line	Description	Section	Amount	Includable Amount	Reference
1	Transmission Rents (Account 567)	II.G			
2	Hydro Quebec DC Phase I Support			-	FF1: Page 320.98 (b) Footnote
3	Hydro Quebec DC Phase II Support			-	FF1: Page 320.98 (b) Footnote
4	New England Power Support			-	FF1: Page 320.98 (b) Footnote
5	Hydro Quebec Phase II NEP AC, Chester SVC			-	FF1: Page 320.98 (b) Footnote
6	Transmission Line Rents		-	-	FF1: Page 320.98 (b) Footnote
7	Total Transmission Rents Received		-	-	Sum Lines 2 thru 6
8	Transmission Related Integrated Facilities Charges	II.I	-	-	
9	- none -		-	-	
10	Total Trans Related Integrated Facilities Charges		-	-	Sum Lines 9 thru 9
11	Transmission Support Revenues 456 & 456.1	II.J			
12	Item #1			$ -	FF1: Page 300.21(b) Footnote
13	Item # 2			-	FF1: Page 300.21(b) Footnote
14	Last Item		-	-	FF1: Page 300.22(b) Footnote
15	Total Short Term & Non-Firm PTP Revenues		$ -	$ -	Sum Lines 12 thru 14
16	Transmission Support Expense (565)	II.K			
17	Item #1			-	FF1 Q2: Page 332.2(h)
18	Item # 2			-	FF1 Q3: Page 332.2(h)
19	Last Item		-	-	FF1: Page 332.2(h)
20	Total Transmission Support Expense		-	-	Sum Lines 17 thru 19
21	Transmission Related Expense from Generators	II.L			N/A
22	- none -		-	-	
23	Total Trans Related Expense from Generators		-	-	Sum Lines 22 thru 22
24	Rents Received from Electric Property (454)	II.M			
25	Item #1			-	FF1: Page 300.19(b) Footnote
26	Item # 2			-	FF1: Page 300.19(b) Footnote
27	Last Item		-	-	FF1: Page 300.19(b) Footnote
28	Total Rents Received		-	-	Sum Lines 25 thru 27
29	Short-Term and Non-Firm Point-to-Point Rev	II.N	$ -	$ -	N/A
30	- none -		-	-	
31	Total ST and Non-Firm Point-to-Point Revenues		-	-	Sum Lines 30 thru 30
32	Regional Network Service Revenues (456):	II.O			
33	RNS Transmission Revenue		-	-	
34	RNS PTF Post 2003 investment 1 % Adder		-	-	RNS Revenue Requirement
35	RNS PTF RTO Participation 0.5% Adder		-	-	RNS Revenue Requirement

36	Total Regional Network Services Revenues		-	-	Sum Lines 33 thru 35
37	Through or Out Revenues	II.P	$ -	$ -	N/A
38	- none -		-	-	
39	Total Through or Out Revenue		-	-	Sum Lines 38 thru 38
40	ISO-NE Scheduling & Dispatch Revenue	II.Q			
41	Nepool Scheduling & Dispatch Revenue		-	-	
42	RTO Participation 0.5% Adder		-	-	Reguional Schedule 1 Revenue Requirement
43	Total ISO-NE Scheduling & Dispatch Revenue		-	-	Sum Lines 42 thru 42

NSTAR Electric Company

Allocation Factors

Service Year Ended December 31, xxxx

Sheet 6

	(a)	(b)	(c)	(d)
Line	**Description**	**Tariff Section**	**Amount**	**Reference**
	Transmission Wages & Salaries Allocation			
1	**Factor**	I.A.1		
2	Transmission Related Direct Wages & Salaries		$ -	FF1: Page 354.21(b)
3	Total Direct Wages & Salaries		-	FF1: Page 354.28(b)
4	Administrative & General Wages & Salaries		-	FF1: Page 354.27(b)
5	Net Total Direct Wages & Salaries		-	Line 3 less Line 4
6	Transmission Wages & Salaries Allocation Factor		**0.0000%**	Line 2 / Line 5
7	**Plant Allocation Factor**	I.A.2		
8	Transmission Plant Investment		$ -	FF1: Page 207.58(g)
9	HQ Leases		-	
10	Transmission Related General Plant		-	Sheet 3, Line 2, Col (f)
11	Transmission Related Intangible Plant		-	Sheet 3, Line 3, Col (f)
12	Total Transmission Plant Investment		-	Sum Lines 8 thru 11
13	Total Plant in Service		-	FF1: Page 207.104(g)
14	Plant Allocation Factor		**0.0000%**	Line 12 / Line 13

15	**Construction Work in Progress Allocation Factor**	II.A.1.d	**50.0000%**

NSTAR Electric Company

Cost of Long Term Debt

Service Year Ended December 31, xxxx

Sheet 7

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	FF1:256(a)	FF1:256(d)		FF1:256(e)	FF1:256(b)	FF1:256(h)		FF1:256(c)					
		Long Term Debt				Principal		Debt	Call				
			Term	Coupon	Original	Amount	Percent	Disc &	Premium on	Net	Cost to	Weighted	
Line	Series	Dated	(Years)	Rate	Issue	Outstanding	of Total	Exp	Debt	Proceeds	Maturity	Cost	Reference
							Col f / Col f Total			**Col f - Col h - Col i**	**Col d + ((Col h + Col i) / (Col e / Col d))**	Col h * Col g	
1	MIFA Bonds	2/8/94	20	5.75%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
2	4.875% Debentures	4/13/04	10	4.875%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
3	7.8% Debentures	5/10/95	15	7.80%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
4	4.875 Debentures	10/9/02	10	4.875%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
5	5.75% Debentures	3/13/06	30	5.750%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
6	5.625% Debentures	11/19/07	10	5.63%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
7	Total				$ -	$ -	0.00%	$ -	$ -	$ -		0.0000%	Sum Lines 1 Thru 6

Cost of Preferred Stock

	Series	Dated	Term	Coupon Rate	Original Issue	Principal Amount Outstanding	Percent of Total	Weighted Cost	Reference
	FF1:250(a)			FF1:250(a)		FF1:250(f)			
		Preferred Stock							
8	4.25%	6/13/1956	N/A	4.25%			0	0.0000%	FF1: Page 250 & 251
9	4.78%	7/10/1958	N/A	4.78%			0	0.0000%	FF1: Page 250 & 251
10	Total				$ -	$ -	0.00%	0.0000%	Sum Lines 8 Thru 9

Effective NSTAR ROI

Tariff Section II.A.2.a

	(a)	(b)	(c)	(d)	(e)	(f)
Line	**Description**	**Common**	**Preferred**	**LTD**	**Total**	**Reference**
11	Amount				$ -	Sheet 2, lines 2 thru 4
12	Cost	0.0000%	0.0000%	0.0000%		See Note
13	Actual Weighting	0.0000%	0.0000%	0.0000%	0.0000%	Line 11 / Total Line 11
14	Weighted Cost	0.0000%	0.0000%	0.0000%	0.0000%	Line 12 * Line 13
15	70% of Weighted Cost	0.0000%	0.0000%	0.0000%		Line 14 * 70%
16	Tariff Weighting	50.0000%	0.0000%	50.0000%	100.0000%	Tariff Section II.A.2.a
17	Weighted Cost	0.0000%	0.0000%	0.0000%	0.0000%	Line 12 * Line 16
18	30% of Weighted Cost	0.0000%	0.0000%	0.0000%		Line 17 * 30%
19	Blended Cost of Capital	0.0000%	0.0000%	0.0000%	0.0000%	Line 15 + Line 18

20	**Lower of Blended or Actual**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	Lower of line 14, col (e) or line 19, col (e)
						Tariff Section II.A.2.a
21	Note:					
22	The Regurn on Equity component is specified in Tariff Section II.A.2.a.iii					
23	The Cost of Preferred Stock is calculated on line 10					
24	The Cost of Long Term Debt is calculated on line 7					

NSTAR Electric Company

Annual Local Network Service Revenue Requirement

Service Year Ended December 31, xxxx

Sheet 8

Transmission Related ADIT - Tariff Section II.A.1.f

	(a)	(b)	(c)	(d)	(e)
Line	Description	Amount	Allocator	Rate Base	Notes
1	**Account 190**				
2	Item # 1		0.0000%	$ -	FF1: Page 234.2(c) Footnote
3	Item #2		0.0000%	-	FF1: Page 234.2(c) Footnote
4	Last Item	-	0.0000%	-	FF1: Page 234.2(c) Footnote
5	Total 190	$ -	0.0000%	$ -	Sum Lines 2 thru 4
6	**Account 283**				
7	Item # 1		0.0000%	-	FF1: Page 276.3(k) Footnote
8	Item #2		0.0000%	-	FF1: Page 276.3(k) Footnote
9	Last Item	-	0.0000%	-	FF1: Page 276.3(k) Footnote
10	Total 283	$ -	0.0000%	$ -	Sum Lines 7 thru 9
11	Wages & Salary Allocator	0.0000%			Sheet 6, Line 6, Col (d)
12	Plant Allocator	0.0000%			Sheet 6, Line 14, Col (d)

ATTACHMENT L

CREDITWORTHINESS POLICY

I. General Information:

This Attachment L details the specific requirements for the creditworthiness procedures of NSTAR. All customers taking (i) any service under Schedule 21-NSTAR or (ii) any FERC-regulated interconnection service from NSTAR must meet the terms of this Policy (where all the above, collectively, are referred to as “Services”). The creditworthiness of each customer must be established prior to receiving service from NSTAR. A customer will be evaluated at the time its application for service is provided to NSTAR. A credit review shall be conducted for each transmission customer not less than annually or upon reasonable request by the transmission customer. This Attachment L, when updated, will be done so in accordance with Section 10 of this Policy and as posted on NSTAR’s OASIS.

All customers must comply with the terms of this Attachment L. Each customer should refer to NSTAR’s web site at www.nstar.com, or NSTAR’s OASIS site, for the NSTAR representative to whom to forward the information required by this Attachment L.

Upon receipt of a customer’s information, NSTAR will review it for completeness and will notify the customer if additional information is required. Upon completion of an evaluation of a customer, NSTAR will notify the customer of its Financial Assurance requirements. NSTAR will provide a written evaluation, upon request, to customers who are not required to provide Financial Assurance.

II. Financial Information:

Customers receiving transmission service or requesting interconnection service must submit, if available, the following:

- All current rating agency reports from Standard and Poor’s (“S&P”), Moody’s and/or Fitch of the customer.
- Audited financial statements provided by a registered independent auditor for the two most recent years, or the period of its existence, if shorter, for the customer.

III. Creditworthiness Requirements:

A. The customer must meet at least one of the following quantitative criteria in order to receive unsecured credit equivalent to 3 months of transmission charges or, for interconnections, the credit equivalent of 3 months of the annual facilities charges and other ongoing charges:

i) If rated, the customer must have either for itself or for its outstanding debt the following:

- Standard and Poor's or Fitch rating of at least a BBB, or
- Moody's rating of at least a Baa2.

ii) If un-rated or if rated below BBB/Baa2, as stated in a), the customer must meet all of the following:

- A Current Ratio of at least 1.0 times (current assets divided by all current liabilities);
- A Total Capitalization Ratio of less that 60% debt: total debt (including all short-term borrowing) divided by total shareholders' equity plus total debt;
- "Earnings before interest, taxes, depreciation and amortization" in most recent fiscal quarter divided by expense for interest" (EBITDA-to-Interest Expense Ratio) of at least 2.0 times; and
- Audited Financial Statement with an unqualified audit opinion.

iii) If the customer relies on the creditworthiness of a parent company, the customer's parent company must meet the criteria set out in (a) or (b) above, and must provide to NSTAR a written guarantee that it will be unconditionally responsible for all financial obligations associated with the customer's receipt of transmission service from NSTAR.

iv) If the customer is a municipal that is a member of the Massachusetts Municipals Wholesale Electric Cooperative (MMWEC), MMWEC must meet the criteria set out in (a) or (b) above and provide to NSTAR a written guarantee that MMWEC will be unconditionally responsible for all financial obligations associated with the customer's receipt of transmission service from NSTAR.

B. If the customer does not qualify for unsecured credit under Section A, the customer will qualify

for unsecured credit equivalent to two months of transmission service charges, or for interconnections, the credit equivalent of two months of the annual facilities charges and other ongoing charges, if one of the following qualitative factors is met:

? The customer has, on a rolling basis, 12 consecutive months of payments to NSTAR with no missed, late or defaults in payment; or

? The customer has an executed long-term contract for the sale of the full output (energy and capacity) of its generating unit and either has executed a corresponding service agreement under Schedule 21-NSTAR for the transmission of that output or the execution of such a service agreement is pending the customer's demonstration of creditworthiness pursuant to this Attachment L.

IV. Financial Assurance:

If the customer does not meet the applicable requirements for Creditworthiness set out in Section III above, then the customer must either:

- Pay in advance for service an amount equal to the lesser of the total charge for Transmission Service or the charge for three months of Transmission Service not less than 5 days in advance of the commencement of service; or

- Obtain Financial Assurance in the form of a: letter of credit, performance bond, or corporate guarantee equal to the equivalent of 3 months of Transmission Service charges prior to receiving service.

If the customer pays for service in advance, NSTAR will pay to the customer interest on the amounts not yet due to NSTAR , computed in accordance with the Commission's regulations at 18 CFR ? 35.19a(a)(2)(iii).

V. Contesting Creditworthiness Determination:

The Transmission Customer may contest NSTAR's determination of creditworthiness by submitting a written request for re-evaluation within 20 calendar days of being notified of the creditworthiness determination. Such request should provide information supporting the basis for a request to re-evaluate a

Transmission Customer's creditworthiness. NSTAR will review and respond to the request within 20 calendar days.

VI. Process for Changing Credit Requirements:

In the event that NSTAR plans to revise its requirements for credit levels or collateral requirements as detailed in this Attachment L, NSTAR shall submit such changes in a filing to the Commission under Section 205 of the Federal Power Act. NSTAR shall follow the notification requirements pursuant to Section 3.04(a) of the Transmission Operating Agreement and reflected herein.

A. General Notification Process

i) NSTAR shall provide written notification to ISO-NE and stakeholders of any filing described above, at least 30 days in advance of such filing.

ii) Filing notifications shall include a detailed description of the filing, including a redlined document containing revised change(s).

iii) NSTAR shall consult with interested stakeholders upon request.

iv) Following Commission acceptance of such filing and upon the effective date, NSTAR shall revise Attachment L and an updated version of Schedule 21-NSTAR shall be posted the ISO-NE website.

B. Transmission Customer Responsibility

When there is a change in requirements pursuant to this Attachment L, it is the responsibility of the customers to forward updated financial information to NSTAR at the address noted on NSTAR's OASIS site and indicate whether the change affects their ability to meet the requirements of this Attachment L. In such cases where the customer's status has changed, the customer must take the necessary steps to comply with the revised requirements of the Attachment L by the effective date of the change.

VII. Posting Collateral Requirements:

A. Changes in Customer's Financial Condition

Each customer must inform NSTAR, in writing, within five (5) business days of any material change in its financial condition, and, if the customer qualifies under Section III.A(c), that of its parent company. A material change in financial condition may include, but is not limited to, the following:

- Change in ownership by way of a merger, acquisition or substantial sale of assets;
- A downgrade of long- or short-term debt rating by a major rating agency;
- Being placed on a credit watch with negative implications by a major rating agency;
- A bankruptcy filing;
- Any action requiring filing of a Form 8-K;
- A declaration of or acknowledgement of insolvency;
- A report of a significant quarterly loss or decline in earnings;
- The resignation of key officer(s);
- The issuance of a regulatory order and/or the filing of a lawsuit that could materially adversely impact current or future financial results.

B. Change in Creditworthiness Status

- A customer who has been extended unsecured credit under this policy must comply with the terms of Financial Assurance in Section IV above if one or more of the following conditions apply:
- The customer no longer meets the applicable criteria for Creditworthiness in Section III above;
- The customer exceeds the amount of unsecured credit extended by NSTAR, in which case Financial Assurance equal to the amount of excess must be provided within 5 business days; or
- The customer has missed two or more payments for any of the services offered by NSTAR in the last 12 months.

In the event that NSTAR determines that there is a change in the credit level or collateral requirements, the customer may request a written explanation of the basis for this change. Such notification should be

sent to the NSTAR contact indicated on the NSTAR OASIS site. NSTAR shall respond to such request within 20 days of receipt of such notification.

Unless otherwise noted above, when there is a change in a customer's Creditworthiness Status requiring the customer to provide Financial Assurance, the customer must provide such Financial Assurance within 20 business days from the date the customer either notifies NSTAR, as required in Section VI.B above, or receives notice from NSTAR.

VIII. <u>Ongoing Financial Review</u>:

Each customer is required to submit to NSTAR annually or when issued, as applicable:

- Current rating agency report;
- Audited financial statements from a registered independent auditor; and
- 10-Ks and 8-Ks, promptly upon their issuance.

IX. <u>Suspension of Service</u>:

NSTAR may immediately suspend service (with notification to Commission) to a customer, and may initiate proceedings with Commission to terminate service, if the customer does not meet the terms described in Sections III through VIII above at any time during the term of service or if the customer's payment obligations to NSTAR exceed the amount of unsecured or secured credit to which it is entitled under this Attachment L. A customer is not obligated to pay for transmission service that is not provided as a result of a suspension of service.

Eversource

SCHEDULE 21-ES

Table of Contents

Schedule ES-4: Charge Provisions for Local Network Service

Appendix A: Network Formula Requirements for Category A Costs

Appendix B: Network Formula Requirements for Category B Costs

Attachment ES-C: Available Transfer Capability Methodology

Attachment ES-D: Penalty Disbursement Methodology

Attachment ES-E: Localized Costs Responsibility Agreement

Attachment ES-G: Network Operating Agreement

Attachment ES-H: Annual Transmission Revenue Requirements

Attachment ES-I: Annual Localized Transmission Revenue Requirement

Attachment ES-L: Creditworthiness Procedures

SCHEDULE 21-ES

LOCAL SERVICE SCHEDULE

This Local Service Schedule, designated Schedule 21-ES, governs the terms and conditions of service taken by Transmission Customers over the Transmission System of The Connecticut Light and Power Company, Public Service Company of New Hampshire and Western Massachusetts Electric Company (together, “Eversource”), but not over the Transmission System of their affiliate, NSTAR Electric Company, which provides service pursuant to Schedule 21-NSTAR.

I. COMMON SERVICE PROVISIONS

1 Definitions

Capitalized terms not defined herein shall have the meanings given them in the Tariff.

1.1 Annual Transmission Costs

The total annual cost of the Transmission System for purposes of Local Network Service shall be the amount specified in Attachments ES-H and ES-I, until amended by Eversource or modified by the Commission.

1.2 Annual True Up

The reconciliation to actual costs and actual loads of the estimated costs and loads costs used for billing purposes under Section 3.0 of this Local Service Schedule for any Service Year.

1.3 Category A Load Ratio Share

Ratio of a Transmission Customer's Category A Network Load to Eversource’s total load computed in accordance with Sections 16.5 and 16.6 under Part III of this Local Service Schedule and calculated on a rolling twelve month basis. Also referred to as “Load Ratio Share”.

1.4 Category B Load Ratio Share

Ratio of a Transmission Customer’s Monthly Category B Load in the Designated State or Area for a Localized Facility to the Monthly Transmission System Category B Load for such Designated State or Area, calculated in accordance with Sections 16.5 and 16.6, and calculated on a rolling twelve month basis.

1.5 Designated Agent

See Tariff. Also, the Designated Agent of Eversource is Eversource Energy Service Company ("Eversource Service") which is a subsidiary of Eversource Energy.

1.6 Designated State or Area

The state or area to which the Commission allocates the costs of a Localized Facility identified in Section 16.3.

1.7 **Interest**

The amount computed in accordance with the Commission's regulations at 18 CFR §35.19a (a)(2)(iii). Interest on deposits and shall be calculated from the day the deposit check is credited to Eversource's account.

1.8 **Interruption**

A reduction in non-firm transmission service due to economic reasons pursuant to Schedule 21.

1.9 **Localized** Facility

Facility or costs that the New England System Operator determines should not be included in Attachment F of the ISO OATT.

1.10 **Network Load**

The load that a Network Customer designates for Local Network Service. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements for any Point-To-Point Transmission Service that may be necessary for such non-designated load.

1.11 **Network Operating Agreement**

An executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Local Network Service under Part III of this Local Service Schedule.

1.12 **Network Upgrades**

Modifications or additions to transmission-related facilities that are integrated with and support Eversource's overall Transmission System for the general benefit of all users of such Transmission System.

1.13 **New England System Operator**

ISO New England Inc. ("ISO") or its successor entity.

1.14 **Party(ies)**

Eversource and the Transmission Customer receiving service under the Tariff.

1.15 **Short-Term Firm Point-To-Point Transmission Service**

Firm Point-To-Point Transmission Service with a term of less than one year.

1.16 Service Agreement

Service Agreement is a transmission service agreement for transmission service provided under this Local Service Schedule or Localized Costs Responsibility Agreement ("LCRA").

1.17 **Service Year**

The calendar year in which the Transmission Customer is receiving service under this Local Service Schedule.

1.18 **Eversource**

The Connecticut Light and Power Company, Western Massachusetts Electric Company, and Public Service Company of New Hampshire, each an operating company of Eversource Energy, but excluding their affiliate NSTAR Electric Company, which provides Transmission Service pursuant to Schedule 21-NSTAR.

1.19 **Eversource's Monthly Transmission System Peak**

The maximum firm usage of the Eversource Transmission System in a calendar month (this does not include load of Eversource's customers exclusively connected to PTF).

1.20 **Eversource Transmission System**

The PTF and non-PTF facilities owned, controlled or operated by Eversource that are used to provide transmission service under this Local Service Schedule. This includes PTF facilities whose costs are not included in the regional rate.

1.21 **Transmission Service**

Point-To-Point Transmission Service provided under this Local Service Schedule on a firm and non-firm basis.

2. Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. Eversource is required to provide (or offer to arrange with the New England System Operator as discussed below), and the Transmission Customer is required to purchase, the following Ancillary Service (i) Scheduling, System Control and Dispatch.

The Transmission Customer serving load within the Eversource Control Area shall also obtain the following ancillary services: (i) Reactive Supply and Voltage Control from Generation Sources, (ii) Regulation and Frequency Response, (iii) Energy Imbalance, (iv) Operating Reserve - Spinning, and (v) Operating Reserve - Supplemental.

The Transmission Customer serving load within the Eversource Control Area is required to acquire the appropriate Ancillary Services, whether from the New England System Operator, Eversource, another party, or by self-supply.

The Transmission Customer may not decline Eversource's or the New England System Operator's offer of appropriate Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from Eversource.

If Eversource is unable to provide Scheduling, System Control and Dispatch, Eversource can fulfill its obligation to provide this Ancillary Service by acting as the Transmission Customer's agent to secure this Ancillary Service from the New England System Operator. The Transmission Customer may elect to (i) have Eversource act as its agent to obtain Scheduling, System Control and Dispatch, (ii) secure Scheduling, System Control and Dispatch directly from the New England System Operator, or from a third party.

Eversource or New England System Operator shall specify the rate treatment and all related terms and conditions in the event of an unauthorized use of Ancillary Services by the Transmission Customer.

The specific Ancillary Services, prices and/or compensation methods are described on the Schedule that is attached to and made a part of the Tariff. Three principal requirements apply to discounts for Ancillary Services provided by Eversource in conjunction with its provision of transmission service as follows: (1) any offer of a discount made by Eversource must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one’s wholesale merchant or an Affiliate’s use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. A discount agreed upon for an Ancillary Service must be offered for the same period to all Eligible Customers on the Eversource system.

3. Billing and Payment

3.1 **Billing Procedure**

Within a reasonable time after the first day of each month, Eversource Service shall submit an invoice to the Transmission Customer for the charges for all services furnished or costs allocated under the Tariff during the preceding month.

The invoice shall be paid by the Transmission Customer within twenty five (25) days of the date of the invoice. All payments shall be made in immediately available funds payable to Eversource Service, or by wire transfer to a bank named by Eversource Service. Billing hereunder shall be based on cost estimates made by Eversource subject to Annual True-up when actual costs for the Service Year are known. Such Annual True-up shall occur no later than six (6) months after the close of the Service Year to which the Annual True-up relates. The Annual True-up will include interest calculated in accordance with Section 35.19a of the Commission’s regulations. If the in

service date of a forecasted capital addition changes, and the impact of such change on Eversource's annual revenue requirement is ten percent or more, Eversource Service will adjust current billing to the Transmission Customer as appropriate.

3.2 Interest on Unpaid Balances

Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by Eversource Service.

3.3 Customer Default

In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to Eversource Service on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after Eversource Service notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, Eversource may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between Eversource and the Transmission Customer, Eversource will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then Eversource may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy. Neither Party shall have the right to challenge any monthly bill or to bring any court or administrative action of any kind questioning the propriety of any bill after a period of twenty four (24) months from the date the bill was due; provided, however, that in the case of a bill based on estimates, such twenty-four month period shall run from the due date of the final adjusted bill.

3.4 Transmission Customer Right to Audit

Eversource shall keep complete and accurate accounts and records with respect to its performance under this Local Service Schedule and shall maintain such data for a period of at least two (2)

years after final billing for audit by a Transmission Customer. The Transmission Customer shall provide thirty (30) days' written notice to Eversource to request an audit of all such accounts and records relevant to service provided to the Transmission Customer for a specific time period. The Transmission Customer shall have the right, during normal business hours and at its own expense, to examine, inspect and make copies of all such accounts and records relevant to service provided to the Transmission Customer at such offices where such accounts and records are maintained, insofar as may be necessary for the purpose of ascertaining the reasonableness and accuracy of all relevant data, estimates or statements of charges submitted hereunder to the Transmission Customer. The records made available to a Transmission Customer for auditing purposes hereunder shall not include information pertaining to the loads of or charges to an individual customer other than the Transmission Customer; unless the Transmission Customer requests that the Commission order that such information be made available to the Transmission Customer and the Commission so orders. Nothing in this section shall be interpreted as limiting the Transmission Customer's access to system-wide load or charge data.

3.5 Regulatory Oversight of Formula Rate

Eversource will submit to the Connecticut Public Utilities Regulatory Authority, the Massachusetts Department of Public Utilities and the New Hampshire Public Utilities Commission ("State Commissions") the following information:

(a) A copy of the New England Power Pool's ("NEPOOL's") or any successor's annual informational filing at FERC supporting the total transmission revenue requirement for New England, which contains information submitted by Eversource supporting its total transmission revenue requirement;

(b) Eversource's total transmission revenue requirement as calculated in Attachments H & I under Schedule 21-ES;

(c) A copy of Eversource's applications under Restated NEPOOL Agreement Section 15.5, concerning the installation of or material changes to transmission facilities (or any successor approval process), and Section 18.4, concerning plans for additions, retirements, or changes in the capacity of transmission facilities (including descriptions of facilities and cost estimates);

(d) A copy of ISO New England's or any successor's Regional Transmission System Plan, which contains all identified improvements to the New England power system approved by the ISO New England or any successor's board;

(e) A copy of Eversource's filing to each New England state's siting council for those projects to be recovered through the RNS or LNS rates, such copy to be filed with the State Commissions when the estimated costs of the projects in question are proposed to be included in the RNS and LNS rates;

(f) At the same time that new estimated rates are implemented, the estimated cost for each capital addition (on a project-by-project basis) the cost of which is to be included in the estimated rates; and, for each such capital addition with an estimated cost of $20 million or greater, Eversource will provide the following to the extent available: (i) a breakdown of the projected cost into the following categories: labor (broken down into planning, engineering, construction, and other), outside services (broken down into planning, engineering, construction and other), materials (broken down into station equipment, towers and poles, overhead conductor, underground conduit and conductor, and other), land (broken down into fee ownership, easement, and other), and other (if applicable) and (ii) a non-binding estimate of the total project costs by calendar quarter;

(g) Within 60 days after the true-up is rendered for a year, the actual cost for each capital addition that was placed in service during that year; and, for each such capital addition with an actual or estimated cost of $20 million or greater, Eversource will provide the following to the extent available: (i) a breakdown of the actual cost into the following categories: labor (broken down into planning, engineering, construction, and other), outside services (broken down into planning, engineering, construction, and other), materials (broken down into station equipment, towers and poles, overhead conductor, underground conduit and conductor, and other), land (broken down into fee ownership, easement, and other), and other (if applicable) and (ii) the actual total project costs by calendar quarter.

4. Regulatory Filings

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the right of Eversource to unilaterally make application to the Commission for a change in rates, terms and

conditions, charges, classification of service, Service Agreement, rule or regulation under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the ability of any Party receiving service under the Tariff to exercise its rights under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

5. Creditworthiness: See Attachment ES-L to this Schedule 21-ES.

6. Rights Under The Federal Power Act

Nothing in this section shall restrict the rights of any party to file a complaint with the Commission under relevant provisions of the Federal Power Act.

II. POINT-TO-POINT TRANSMISSION SERVICE

Scheduling of Point-To-Point Transmission Service:

The System Operator will dispatch all resources subject to its control, pursuant to Market Rule 1, in order to meet load and to accommodate external transactions. Resources within the New England Control Area using Firm Point-to-Point Transmission Service shall be dispatched based on economic merit in accordance with Market Rule 1 and will have no physical scheduling or dispatch rights. Transmission Customers will be charged for congestion costs and any other costs associated with such dispatch in accordance with Market Rule 1.

7. Nature of Firm Point-To-Point Transmission Service

7.1 Classification of Firm Transmission Service

The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedule ES-2, as appropriate, for Long and Short-Term Firm Point-To-Point Transmission Service. In the event that either a Transmission Customer has not made a capacity reservation, or a Transmission Customer exceeds its firm capacity reservation at the Point of Receipt and Point of Delivery the Transmission Customer shall be billed and pay for its actual use of such excess capacity in addition to any Reserved Capacity pursuant to Schedule ES-2, including ancillary services provided pursuant to Schedule ES-1 hereto.

8. Nature of Non-Firm Point-To-Point Transmission Service

8.1 Classification of Non-Firm Point-To-Point Transmission Service

The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedule ES-3, as appropriate, for non-firm Point-To-Point Transmission Service. In the event that either a Transmission Customer has not made a capacity reservation, or a Transmission Customer exceeds its non-firm capacity reservation at any Point of Receipt or Point of Delivery, the Transmission Customer shall be billed and pay for its actual use of such excess capacity in addition to any Reserved Capacity pursuant to Schedule ES-3, including ancillary services provided pursuant to Schedule ES-1 hereto. Non-Firm Point-To-Point Transmission Service shall include transmission of energy on an hourly basis and transmission of scheduled short-term capacity and/or energy on a daily, weekly or monthly basis, but not to exceed one month's reservation for any one Application, under Schedule ES-3.

9. Service Availability

9.1 Real Power Losses

Real Power Losses are associated with all transmission service. Eversource is not obligated to provide Real Power Losses. The Transmission Customer is responsible for replacing losses associated with all transmission service as determined under Market Rule 1. The applicable Real Power Loss factors are as follows:

The amount of transmission losses incurred in transmitting power from the POR(s) to the POD(s) ("Loss Amount") shall be determined from time to time by the New England System Operator in accordance with ISO procedures applicable at the time of delivery. The Loss Amounts, when determined by the New England System Operator, shall be posted on Eversource’s Open Access Same-Time Information System ("OASIS"). In the event that the New England System Operator, for any reason, does not determine the entire Loss Amount, the losses not determined by the New England System Operator shall be based on average system losses as set forth below:

Cumulative Losses in Percent

POR/POD	Peak*	Off-Peak	24 Hr. Avg.
Bulk Transmission	1.98	2.42	2.21
Bulk Substation	2.46	2.92	2.70
Pri. Distribution	4.58	4.50	4.54

*Peak hours are defined as 0700-2300, Monday-Friday; Off-Peak hours are all other hours.

10. Procedures for Arranging Firm Point-To-Point Transmission Service

10.1 Deposit

A Completed Application for Firm Point-To-Point Transmission Service also shall include a deposit of either three month's charge for Reserved Capacity or the full charge for Reserved Capacity for service requests of less than one month.

11. Additional Study Procedures For Firm Point-To-Point Transmission Service Requests:

11.1 Disbursement Methodology for Late Study Penalties

See Attachment ES-D to Schedule 21-ES.

12. Compensation for Transmission Service

The Transmission Customers taking Point-To-Point Transmission Service shall pay Eversource for any Direct Assignment Facilities, Ancillary Services and applicable study costs, along with the following:

12.1 Rates and Charges for Transmission Service

Rates for Firm and Non-Firm Point-To-Point Transmission Services are provided in the Attachments appended to this Local Service Schedule: Firm Point-To-Point Transmission Services (Schedule ES-2); and Non-Firm Point-To-Point Transmission Services (Schedule ES-3).

12.2 Rates for Firm and Non-Firm Point-To-Point Transmission Services

Rates for Firm and Non-Firm Point to Point Transmission Services shall be determined as set forth in Attachments ES-2 and ES-3 of this Local Service Schedule on the basis of estimated

costs for each Service Year until the actual costs for such Service Year are determined. Thereafter, payments made on such estimated costs shall be recalculated based on actual data for that Service Year, and an appropriate billing adjustment shall be made pursuant to Section 3 of this Local Service Schedule. Eversource shall use Part II of the Tariff to make its Third-Party Sales. Eversource shall account for such use at the applicable Tariff rates.

III. LOCAL NETWORK SERVICE

13. Nature of Local Network Service

13.1 Real Power Losses

Real Power Losses are associated with all transmission service. Eversource is not obligated to provide Real Power Losses. The Network Customer is responsible for replacing losses associated with all transmission service as determined under Market Rule 1. The applicable Real Power Loss factors are as follows:

The amount of transmission losses incurred in transmitting power across the Eversource Transmission System to the Network Customer's Network Load shall be determined from time to time by the New England System Operator in accordance with ISO procedures applicable at the time of delivery. The Loss Amounts, when determined by the New England System Operator, shall be posted on the Open Access Same-Time Information System ("OASIS"). In the event that the New England System Operator, for any reason, does not determine the entire Loss Amount, the losses not determined by the New England System Operator shall be based on average system losses as set forth below:

Cumulative Losses in Percent

POR/POD	Peak*	Off-Peak	24 Hr. Avg.
Bulk Transmission	1.98	2.42	2.21
Bulk Substation	2.46	2.92	2.70
Pri. Distribution	4.58	4.50	4.54

*Peak hours are defined as 0700-2300, Monday-Friday; Off-Peak hours are all other hours.

14. Network Resources

14.1 Use of Interface Capacity by the Network Customer

There is no limitation upon a Network Customer's use of the Eversource Transmission System at any particular interface to integrate the Network Customer's Network Resources (or substitute economy purchases) with its Network Loads. However, a Network Customer's use of Eversource's total interface capacity with other transmission systems may not exceed the Network Customer's Load.

15. Additional Study Procedures For Local Network Service Requests

15.1 Disbursement Methodology for Late Study Penalties See Attachment ES-D to Schedule 21-ES

16. Rates and Charges

The Network Customer shall pay Eversource for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following:

16.1 Rates and Charges

Rates for Local Network Service shall be determined as set forth in Schedule ES-4 on the basis of estimated costs for each Service Year until the actual costs for such Service Year are determined. Thereafter, payments made on such estimated costs shall be recalculated based on actual data for that Service Year, and an appropriate billing adjustment shall be made pursuant to Section 3 of this Local Service Schedule.

16.2 Eligible Customers Taking Service Under the ISO Tariff

Any Eligible Customer taking Regional Network Service under the ISO Tariff in a Designated State or Area shall pay to Eversource Service the customer's Category B Load Ratio Share of the Formula Requirements as calculated in Schedule ES-4, Appendix B for such Designated State or Area**.** Eversource Service shall execute a LCRA under this Local Service Schedule, in the form set forth in Attachment ES-E, to recover such charges from such customer. Eversource Service shall not bill any such customer any such costs until (1) such LCRA has been executed with the

Eligible Customer, or (2) an unexecuted LCRA has been permitted to be made effective **by** the Commission.

16.3 Listing of Localized Facilities by Designated State or Area:

(a) Connecticut:
Bethel to Norwalk Project
Middletown to Norwalk Project
Glenbrook Cables Project
Greater Springfield Reliability Project (Connecticut portion)

(b) Massachusetts:
Greater Springfield Reliability Project (Massachusetts portion)

16.4 **Monthly Demand Charge**

The Network Customer shall pay monthly Demand Charges, which shall be determined by multiplying its Category A Load Ratio Share times one twelfth (1/12) of the Formula Requirements in Schedule ES-4, Appendix A, and by multiplying its Category B Load Ratio Share for the Designated State or Area times one twelfth (1/12) of the Formula Requirements in Schedule ES-4, Appendix B for the Localized Facilities that are in such Designated State or Area.

16.5 **Determination of Network Customer's Monthly Network Load**

The Network Customer's Monthly Category A Network Load is its hourly load (including its designated Network Load not physically interconnected with Eversource under Schedule 21) coincident with Eversource’s Monthly Transmission System Peak.

The Network Customer’s Monthly Category B Load for a Designated State **or** Area for a Localized Facility is its hourly load in such Designated State or Area coincident with the monthly transmission system peak load for such Designated State or Area.

For Localized Facilities for which the Designated State or Area is identified as “Connecticut” in Section 16.3(a) of this Schedule 21-ES, the customer’s hourly load shall be all of the customer’s

Regional Network Load in Connecticut, and the monthly transmission system peak load shall be all Regional Network Load in Connecticut.

For Localized Facilities for which the Designated State or Area is identified as “Massachusetts” in Section 16.3(b) of this Schedule 21-ES, the customer’s hourly load shall be all of the customer’s Regional Network Load in Massachusetts, and the monthly transmission system peak load shall be all Regional Network Load in Massachusetts; provided, that the customer’s monthly load and the monthly transmission system peak load shall exclude the load of generators taking RNS for the delivery of offline station service.

16.6 **Determination of Eversource’s Monthly Transmission System Load**

Eversource’s Monthly Transmission System Category A Load is Eversource’s Monthly Transmission System Peak minus the coincident peak usage of all Firm Point-To-Point Transmission Service customers pursuant to this Local Service Schedule plus the Reserved Capacity of all Firm Point-To-Point Transmission Service customers.[1]

Eversource’s Monthly Transmission System Category B Load for the Designated State or Area for a **Localized** Facility is the monthly transmission system peak load for such Designated State or Area.[1]

For Localized Facilities for which the Designated State or Area is identified as “Connecticut” in Section 16.3(a) of this Schedule 21-ES, the monthly transmission system peak load shall be all Regional Network Load in Connecticut.

For Localized Facilities for which the Designated State or Area is identified as “Massachusetts” in Section 16.3(b) of this Schedule 21-ES, the monthly transmission system peak load shall be all Regional Network Load in Massachusetts; provided, that the monthly transmission system peak load shall exclude the load of generators taking RNS for the delivery of offline station service.

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[1] Excludes MWs associated with lump sum payment transactions identified in footnote 2.

17. Operating Arrangements

17.1 Operation under the Network Operating Agreement

The Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Network Operating Agreement.

17.2 Network Operating Agreement

The terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Part III of the Tariff shall be specified in the Network Operating Agreement. The Network Operating Agreement shall provide for the Parties to (i) operate and maintain equipment necessary for integrating the Network Customer within the Eversource Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between Eversource and the Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside the Eversource Transmission System, interchange schedules, unit outputs for redispatch, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted loads and resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of Part III of the Tariff, including scheduling protocols. The Network Operating Agreement will recognize that the Network Customer shall either (i) operate as a Control Area under applicable guidelines of the North American Electric Reliability Council (NERC) and the Northeast Power Coordinating Council (NPCC), (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with Eversource, or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies NERC and NPCC requirements. Eversource shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services. The Network Operating Agreement is included in Attachment ES-G.

SCHEDULE ES-1

SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by Eversource (if Eversource is the Control Area operator) or indirectly by Eversource making arrangements with the New England System Operator that performs this service for the Eversource Transmission System. The Transmission Customer must purchase this service from Eversource or the New England System Operator. The charges for Scheduling, System Control and Dispatch Service are to be based on the rates set forth below. To the extent the New England System Operator performs this service for Eversource, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to Eversource by that New England System Operator.

Each Point-To-Point Transmission Customer under this Local Service Schedule will be charged for Transmission Scheduling, System Control and Dispatch Services for the total Reserved Capacity specified in each reservation for Point-To-Point Transmission Service made under this Local Service Schedule at the rates set forth in Appendix A of this Schedule ES-1. In the event that a Transmission Customer utilizes transmission capacity without a reservation or exceeds its capacity reservation at any Point of Receipt or Point of Delivery, the Transmission Customer **shall** pay for its actual use of such excess capacity in addition to any Reserved Capacity. The charge for such excess use of capacity shall be determined by multiplying the sum of the actual use in excess of its capacity reservation times the hourly non-firm rate posted on Eversource's OASIS including ancillary services provided pursuant to Schedule ES-1 hereto.

Each Network Customer under this Local Service Schedule will be charged a monthly Transmission Scheduling, System Control and Dispatch Service Demand Charge, which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of the Formula Requirements specified in Appendix B of this Schedule ES-1.

Each Transmission Customer with generation within the New England Control Area shall be required also to provide for Scheduling, System Control and Dispatch Service for that generation. It is anticipated that the Transmission Customer will obtain these services from the ISO. Eversource will make available

Generation Scheduling, System Control and Dispatch Service at the rates set forth in Appendix C of this Schedule ES-1.

Each Transmission Customer with generation located outside of the New England Control Area shall be required to provide for Scheduling, System Control and Dispatching Service for that generation. It is anticipated that the Transmission Customer will obtain these services by contracting for these services from the provider of these services within the Control Area where the generation is located.

Eversource shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Schedule ES-1 in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE ES-1

Appendix A

POINT-TO-POINT TRANSMISSION RATE

Eversource's Formula Rate for Point-To-Point Transmission Scheduling, System Control and Dispatch Service ("Formula Rate") is an annual rate determined from the following formula.

$$\textit{Formula Rate}_i = (A_{i\text{-}1} - B_{i\text{-}1})\, C_{i\text{-}1} \quad \textit{WHERE:}$$

- i equals the calendar year during which service is being rendered ("Service Year").

- $A_{i\text{-}1}$ is the Annual Control Center Expenses (expressed in dollars) of Eversource for the calendar year prior to the Service Year. The Annual Control Center Expenses are determined pursuant to the formula specified in Exhibit 1 to this Appendix A of Schedule ES-1.

- $B_{i\text{-}1}$ is the actual transmission scheduling, system control and dispatch revenues (expressed in dollars) provided from the provision of transmission services to others. The actual transmission scheduling and dispatch revenues shall be those recorded on the books of each of the companies comprising Eversource hereunder in FERC Account No. 456.1 pertaining to Transmission of Electricity for Others and such other applicable FERC accounts for the calendar year prior to the Service Year.

- $C_{i\text{-}1}$ is the average Eversource Monthly Transmission System Category A Load (expressed in kilowatts).

SCHEDULE ES-1

Appendix A

Exhibit 1

DETERMINATION OF ANNUAL CONTROL CENTER EXPENSES

The rate formula for determination of the annual control center expenses revenue requirements for each of the companies comprising Eversource hereunder is determined as follows:

A. ANNUAL CONTROL CENTER EXPENSES

Eversource's System Control and Load Dispatching Expense, for the calendar year prior to the Service Year, as recorded in FERC Account 561.1-561.4 and the revenue requirement calculation for the CL&P Dispatch Center Plant as described in Appendix A, Exhibit 2.

SCHEDULE ES-1

APPENDIX A

EXHIBIT 2

CL&P DISPATCH CENTER REVENUE REQUIREMENT

This exhibit calculates the CL&P Dispatch Center Revenue Requirement. The CL&P Dispatch Center Revenue Requirement for use during a calendar year shall be based on CL&P's costs for the immediately preceding calendar year.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section I. of the ISO-NE Transmission, Markets and Services Tariff and as used in this exhibit have the following definitions:

<u>Dispatch Center</u> means CL&P's CONVEX dispatch center.

<u>Dispatch Center Plant</u> shall equal CL&P's year-end gross plant balances used for CL&P's Dispatch Center as recorded in FERC Account Nos. 303, 350-359, and 389-399.

<u>Dispatch Center Depreciation Reserve</u> shall equal CL&P's year-end depreciation reserve balance for Dispatch Center Plant as recorded in FERC Account No. 108.

<u>Dispatch Center Accumulated Deferred Income Taxes</u> shall equal the net of CL&P's year-end deferred tax balances for Dispatch Center Plant as recorded in FERC Account Nos. 281-283 and 190.

II. CALCULATION OF TOTAL DISPATCH CENTER REVENUE REQUIREMENT

The Dispatch Center Revenue Requirement shall equal the sum of (A) Dispatch Center Return and Associated Income Taxes, (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Amortization of Investment Tax Credits, and (D) Dispatch Center Municipal Tax Expense; provided, that during the period January 1, 2008 through December 31, 2008, the Dispatch Center Revenue Requirement shall equal the product of (i) the number of months (or fractions thereof) remaining in 2007 on and after the date upon which the CONVEX Agreements are permitted to be made effective by FERC, divided by 12 and (ii) the sum of (A) Dispatch Center Return and Associated Income Taxes, (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Amortization of Investment Tax Credits, and (D) Dispatch Center Municipal Tax Expense. "CONVEX Agreements" refers to the agreements between The

Connecticut Light & Power Company and various entities relating to the operation of the Dispatch Center and filed with FERC contemporaneously with the filing of this Exhibit 2.

A. <u>Dispatch Center Return and Associated Income Taxes</u> shall equal the product of the Dispatch Center Investment Base and the Cost of Capital Rate.

1. Dispatch Center Investment Base

<u>The Dispatch Center Investment Base</u> will be the year-end balances of: (a) Dispatch Center Plant, less (b) Dispatch Center Depreciation Reserve, less (c) Dispatch Center Accumulated Deferred Income Taxes.

2. Cost of Capital Rate

<u>The Cost of Capital Rate</u> will equal (a) the Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon CL&P's capital structure at the end of each year and will equal the sum of (i),(ii), and (iii) below.

(i) The long-term debt component, which equals the product of the year-end balance of CL&P's first mortgage bonds and pollution control notes adjusted for premiums, discounts, debt expense and losses on reacquired debt and the ratio of the long term debt to CL&P's total capital.

(ii) The preferred stock component, which equals the product of the year-end balance of CL&P's preferred stock adjusted for premiums, discounts and unamortized issue expense and the ratio of the preferred stock to CL&P's total capital.

(iii) The common equity component, which equals the product of 10.3% and the ratio of the common equity to CL&P's total capital.

(b and c) Federal and State Income Taxes shall be computed as follows:

A x B x C

where:

A = Dispatch Center Investment Base

B = Cost of equity capital (the sum of the preferred stock component and common equity component)

C = TE / (1-TE), where TE is the effective combined federal and state statutory income tax rates in effect at the applicable time.

B. Dispatch Center Depreciation Expense shall equal CL&P's Dispatch Center depreciation expense as recorded in FERC Account No. 403.

C. Dispatch Center Amortization of Investment Tax Credits shall equal CL&P's Dispatch Center amortization of investment tax credits as recorded in FERC Account No. 411.4.

D. Dispatch Center Municipal Tax Expense shall equal CL&P's Dispatch Center municipal tax expense as recorded in FERC Account Nos. 408.1 and 409.1.

SCHEDULE ES-1

Appendix B

NETWORK TRANSMISSION FORMULA REQUIREMENTS

Eversource's formula requirements for Network Transmission Scheduling, System Control and Dispatch Service is determined from the following formula.

Formula $\text{Requirements}_i = (A_{i\text{-}1} - B_{i\text{-}1})$

WHERE:

- i equals the calendar year during which service is being rendered ("Service Year").

- $A_{i\text{-}1}$ is the Annual Control Center Expenses (expressed in dollars) of Eversource for the calendar year prior to the Service Year. The Annual Control Center Expenses are determined pursuant to the formula specified in Exhibit 1 to this Appendix B of Schedule ES-1.

- $B_{i\text{-}1}$ is the actual transmission scheduling, system control and dispatch revenues (expressed in dollars) provided from the provision of transmission services to others. The actual transmission scheduling, system control and dispatch revenues shall be those recorded on the books of each of the companies comprising Eversource hereunder in FERC Account No. 456.1 pertaining to Transmission of Electricity for Others and such other applicable FERC Account for the calendar year prior to the Service Year.

SCHEDULE ES-1

APPENDIX B

EXHIBIT 1

DETERMINATION OF ANNUAL CONTROL CENTER EXPENSES

The rate formula for determination of the annual control center expenses for each of the companies comprising Eversource hereunder is determined as follows:

A. ANNUAL CONTROL CENTER EXPENSES

Eversource's System Control and Load Dispatching Expense), for the calendar year prior to the Service Year as recorded in FERC Account 561.1-561.4 and the revenue requirement calculation for the CL&P Dispatch Center Plant as described in Appendix B, Exhibit 2.

SCHEDULE ES-1

APPENDIX B

EXHIBIT 2

CL&P DISPATCH CENTER REVENUE REQUIREMENT

This exhibit calculates the CL&P Dispatch Center Revenue Requirement. The CL&P Dispatch Center Revenue Requirement for use during a calendar year shall be based on CL&P's costs for the immediately preceding calendar year.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section I. of the ISO-NE Transmission, Markets and Services Tariff and as used in this exhibit have the following definitions:

Dispatch Center means CL&P's CONVEX dispatch center.

Dispatch Center Plant shall equal CL&P's year-end gross plant balances used for CL&P's Dispatch Center as recorded in FERC Account Nos. 303, 350-359, and 389-399.

Dispatch Center Depreciation Reserve shall equal CL&P's year-end depreciation reserve balance for Dispatch Center Plant as recorded in FERC Account No. 108.

Dispatch Center Accumulated Deferred Income Taxes shall equal the net of CL&P's year-end deferred tax balances for Dispatch Center Plant as recorded in FERC Account Nos. 281-283 and 190.

II. CALCULATION OF TOTAL DISPATCH CENTER REVENUE REQUIREMENT

The Dispatch Center Revenue Requirement shall equal the sum of (A) Dispatch Center Return and Associated Income Taxes, (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Amortization of Investment Tax Credits, and (D) Dispatch Center Municipal Tax Expense; provided, that during the period January 1, 2008 through December 31, 2008, the Dispatch Center Revenue Requirement shall equal the product of (i) the number of months (or fractions thereof) remaining in 2007 on and after the date upon which the CONVEX Agreements are permitted to be made effective by FERC, divided by 12 and (ii) the sum of (A) Dispatch Center Return and Associated Income Taxes, (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Amortization of Investment Tax Credits, and (D) Dispatch Center Municipal Tax Expense. "CONVEX Agreements" refers to the agreements between The

Connecticut Light & Power Company and various entities relating to the operation of the Dispatch Center and filed with FERC contemporaneously with the filing of this Exhibit 2.

A. Dispatch Center Return and Associated Income Taxes shall equal the product of the Dispatch Center Investment Base and the Cost of Capital Rate.

1. Dispatch Center Investment Base

The Dispatch Center Investment Base will be the year-end balances of: (a) Dispatch Center Plant, less (b) Dispatch Center Depreciation Reserve, less (c) Dispatch Center Accumulated Deferred Income Taxes.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) the Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon CL&P's capital structure at the end of each year and will equal the sum of (i),(ii), and (iii) below.

(i) The long-term debt component, which equals the product of the year-end balance of CL&P's first mortgage bonds and pollution control notes adjusted for premiums, discounts, debt expense and losses on reacquired debt and the ratio of the long term debt to CL&P's total capital.

(ii) The preferred stock component, which equals the product of the year-end balance of CL&P's preferred stock adjusted for premiums, discounts and unamortized issue expense and the ratio of the preferred stock to CL&P's total capital.

(iii) The common equity component, which equals the product of 10.3% and the ratio of the common equity to CL&P's total capital.

(b and c) Federal and State Income Taxes shall be computed as follows:

A x B x C

where:

A = Dispatch Center Investment Base

B = Cost of equity capital (the sum of the preferred stock component and common equity component)

C = TE / (1-TE), where TE is the effective combined federal and state statutory income tax rates in effect at the applicable time.

B. Dispatch Center Depreciation Expense shall equal CL&P’s Dispatch Center depreciation expense as recorded in FERC Account No. 403.

C. Dispatch Center Amortization of Investment Tax Credits shall equal CL&P’s Dispatch Center amortization of investment tax credits as recorded in FERC Account No. 411.4.

D. Dispatch Center Municipal Tax Expense shall equal CL&P’s Dispatch Center municipal tax expense as recorded in FERC Account Nos. 408.1 and 409.1.

SCHEDULE ES-1

Appendix C

GENERATION RATES

Eversource's Formula Rate for Generation Scheduling, System Control and Dispatch Service ("Formula Rate") shall be calculated using the Point-to-Point Formula Rate for Transmission Scheduling, System Control, and Dispatch Service in Appendix A of Schedule ES-1.

SCHEDULE ES-2

FIRM POINT-TO-POINT SERVICE

I. Each month, Eversource Service shall bill the Transmission Customer for Long-Term Firm and Short-Term Firm Transmission Service and the Transmission Customer shall be obligated to pay Eversource the charges as set forth in this Schedule ES-2, as applicable.

A. TRANSMISSION CHARGES

1. Determination of Transmission Charges

The Transmission Charges will provide for recovery of the costs of the transmission facilities ofEversource. The Category A Transmission Charges for each month will equal the sum of the Category A Charges for each monthly (or longer term), weekly or daily transaction during such month. In the event that a Transmission Customer utilizes transmission capacity without a reservation or exceeds its capacity reservation at any Point of Receipt or Point of Delivery, the Transmission Customer **shall** pay for its actual use of such excess capacity in addition to the charges for each monthly, weekly or daily transactions during such month. The charge for such excess use of capacity shall be determined by multiplying the actual hourly use in excess of its capacity reservation times the applicable Category A on-peak or off-peak hourly non-firm rate posted on Eversource's OASIS pursuant to Schedule ES-3 including ancillary services provided pursuant to Schedule ES-1 hereto.

The Category A Charge for each monthly (or longer term) transactions will be the product of: (a) Eversource's Category A Formula Rate (expressed in $ per kilowatt-year), divided by twelve (12) months, and (b) the Reserved Capacity set forth for such monthly (or longer term) transaction (expressed in kilowatts).

The Category A Charge for each weekly transaction will be the product of: (a) Eversource's Weekly Category A Short-Term Firm Point-To-Point Transmission Rate (expressed in $ per kilowatt-week), and (b) the Reserved Capacity set forth for such weekly transaction (expressed in kilowatts). Eversource's Weekly Category A Rate is Eversource's Category A Formula Rate for Firm Point-To-Point Transmission Service divided by fifty-two (52) weeks.

The Category A Charge for each daily transaction will be the product of: (a) Eversource's Daily Category A Short-Term Firm Point-To-Point Transmission Rate (expressed in $ per kilowatt-day), and (b) the Reserved Capacity set forth for such daily transaction (expressed in kilowatts). Eversource's Daily Category A Rate is Eversource's Weekly Category A Rate for Short-Term Firm Point-To-Point Transmission Service divided by five (5) days. The total of the Transmission Customer's charges for daily transactions, under an individual reservation, in a seven (7) day period shall not exceed the charges based on the Weekly Category A Rate and the Transmission Customer's maximum Reserved Capacity in the period.

2. Eversource's Formula Rates

Eversource's Formula Rates for Long-Term Firm and Short-Term Firm Point-To-Point Service shall be determined in accordance with the rate formulas specified in Appendix A of this Schedule ES-2.

3. Tax Rates and Taxes

Eversource's Formula Rates set forth in this schedule in effect during a Service Year shall be based on the local, state, and federal tax rates and taxes in effect during the Service Year. If, at any time, additional or new taxes are imposed on Eversource or existing taxes are removed, Eversource's Formula Rate will be appropriately modified and filed with the Commission in accordance with Part 35 of the Commission's regulations.

4. Provision re: Exchanges

With respect to Entitlement Transactions or Energy Transactions or other transactions that involve an exchange, each party to such transaction shall be treated as an individual Transmission Customer under this Local Service Schedule. Accordingly, a separate Schedule ES-2 or other

applicable charge(s) will be calculated for, and a separate bill will be rendered to, each such individual Transmission Customer.

5. Discounts

Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by Eversource must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, Eversource must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

6. Resales

The rates and rules governing charges and discounts in Sections I.A.1 and 5 of this Schedule ES-2 stated above shall not apply to resales of transmission service, compensation for which shall be governed by Schedule 21.

II. In addition to the applicable charges of this Local Service Schedule, and as otherwise specified in the Service Agreement, the Transmission Customer shall pay to Eversource Service each month the following additional charges for Long-Term, and Short-Term Firm Point-To-Point Transmission Service provided during such month.

A. Taxes and Fees Charge

B. Regulatory Expenses Charge

C. Other

A. **TAXES AND FEES CHARGE**

If any governmental authority requires the payment of any fee or assessment or imposes any form of tax with respect to payments made for Long-Term Firm or Short Term Firm Point-To-Point Transmission Service provided under this Local Service Schedule, not specifically provided for in any of the charge or

rate provisions under this Local Service Schedule, including any applicable interest charged on any deficiency assessment made by the taxing authority, together with any further tax on such payments, the obligation to make payment for any such fee, assessment, or tax shall be borne by the Transmission Customer. Eversource will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's regulations.

B. **REGULATORY EXPENSES CHARGE**

Eversource shall have the right to make a Section 205 filing for recovery of regulatory expenses associated with this Local Service Schedule and the Service Agreements.

C. **OTHER**

Eversource shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Schedule ES-2 in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE ES-2

Appendix A

CATEGORY A RATE

FIRM POINT-TO-POINT TRANSMISSION SERVICE

Eversource's Category A Formula Rate for Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service ("Formula Rate") is an annual rate determined from the following formula.
Formula $Rate_i = (A_i - B_i + C_i - D_i) / E_i$

WHERE:

- i equals the Service Year.

- A is the annual Total Transmission Revenue Requirements (expressed in dollars) as described in Attachment ES-H,

- B is the revenues received (expressed in dollars) from the provision of transmission and other related services, to others as recorded in FERC Accounts 456.1 and 454 to the extent that such transactions are not included in the determination of load (E),[2] minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

- C is the transmission payments (expressed in dollars) to the New England System Operator as recorded in FERC Account 565 in accordance with the Tariff.

- D is the sum of the annual revenues received (expressed in dollars) for the costs associated with the Localized Facilities, minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

- E is the average Eversource Monthly Transmission System Category A Load (expressed in kilowatts).

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[2] Includes amortization of revenues from point-to-point transmission service provided to Consolidated Edison Energy Massachusetts, Inc. and NRG Energy, Inc. under contracts in which customers paid based on single lump sum payment.

SCHEDULE ES-2

[Reserved]

SCHEDULE ES-3

NON-FIRM POINT-TO-POINT SERVICE

I. Eversource shall bill the Transmission Customer for Non-Firm Point-To-Point Transmission Service, and the Transmission Customer shall be obligated to pay Eversource the charges as set forth in this Schedule ES-3 as applicable.

A. TRANSMISSION CHARGES

1. General

The Transmission Customer shall pay to Eversource Service each month the Category A Transmission Charges calculated for all of the Transmission Customer's monthly transactions, weekly transactions, daily transactions and hourly transactions, each as set forth below. In the event that a Transmission Customer utilizes transmission capacity without a reservation or exceeds its capacity reservation at any Point of Receipt or Point of Delivery, the Transmission Customer shall pay for its actual use of such excess capacity in addition to the charges for each monthly, weekly, daily or hourly transactions during such month. The charge for such excess use of capacity shall be determined by multiplying the actual hourly use in excess of its capacity reservation times the applicable Category A on-peak or off-peak hourly non-firm rate posted on Eversource's OASIS pursuant to this Schedule ES-3 including ancillary services provided pursuant to Schedule ES-1 hereto.

With respect to any wholesale transactions that involve an exchange, each party to such transaction shall be an individual Transmission Customer under this Local Service Schedule. Accordingly, a Transmission Charge, as applicable, will be calculated for, and a separate bill will be rendered to, each such Transmission Customer.

The Category A Transmission Charge for each month applicable to a monthly transaction shall be determined as the product of: (a) the Category A rate posted on Eversource's Open Access Same-Time Information System ("OASIS") at the time the service is reserved, not to exceed Eversource's Annual Category A Rate for Non Firm Point-To-Point Transmission Service divided by twelve (12) months and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Reservation for such month (expressed in kilowatts).

The Category A Transmission Charge for each month applicable to weekly transactions shall be the sum of the transmission charges determined for each weekly transaction during such month. The transmission charge for each weekly transaction shall be determined as the product of: (a) the Category A rate posted on Eversource's OASIS at the time the service is reserved, not to exceed Eversource's Weekly Category A Firm Point-To-Point Transmission Charge Rate (expressed in $ per kilowatt-week), and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Reservation for such week (expressed in kilowatts). Eversource's Weekly Category A Rate is Eversource's Annual Category A Rate for Non-Firm Point-To-Point Transmission Service divided by fifty-two (52) weeks.

The Transmission Charge for each month applicable to daily transactions will be the sum of the transmission charges determined for each daily transaction. The transmission charge for each daily transaction shall be determined as the product of: (a) the rate posted on Eversource's OASIS at the time the service is reserved, not to exceed Eversource's Daily Category A Firm Point-To-Point Transmission Charge Rate (expressed in $ per kilowatt-day), and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Reservation for such day (expressed in kilowatts). Eversource's Daily Category A On-Peak Rate is Eversource's Weekly Category A Rate for Non-Firm Point-To-Point Transmission Service divided by five (5) days. Eversource's Daily Category A Off-Peak Rate is Eversource's Weekly Category A Rate for Non-Firm Point-To-Point Transmission Service divided by seven (7) days. The total of the Transmission Customer's charges for daily transactions, under an individual Reservation, in a seven (7) day period shall not exceed the charges based on the Weekly Category A Rate and the Transmission Customer's maximum Reserved Capacity in the period.

The Transmission Charge for each month applicable to hourly transactions will be the sum of the transmission charges determined for each hourly transaction during such month. The transmission charge for each hour of an hourly Transaction shall be determined as the product of: (a) the rate posted on Eversource's OASIS at the time the service is reserved, not to exceed Eversource's Daily Category A Firm Point-To-Point Transmission Service Rate divided by sixteen (16) hours (expressed in $ per kilowatt-hour), and (b) the Reserved Capacity as set forth in the Transmission Customer's applicable Reservation for such hour (expressed in kilowatts). Eversource's Hourly Category A On-Peak Rate is equal to Eversource's Daily Category A Rate for Non-Firm Transmission Service divided by sixteen (16) hours. Eversource's Hourly Category A Off-Peak Rate is equal to Eversource's Daily Category A Rate for Non-Firm Transmission

Service divided by twenty-four (24) hours. The total of the Transmission Customer's charges for hourly transactions, under an individual Reservation, in a twenty-four (24) hour period shall not exceed the charges based on the Daily Category A Rate and the Transmission Customer's maximum Reserved Capacity in the period.

2. Discounts

Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by Eversource must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, Eversource must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

3. Resales

The rates and rules governing charges and discounts in Sections I.A.1 and 2 of this Schedule ES-3 stated above shall not apply to resales of transmission service, compensation for which shall be governed by Schedule 21.

4. Credit to the Transmission Charge

Whenever service provided hereunder is interrupted or curtailed by Eversource, the Local Control Center or the New England System Operator, the Transmission Charges to the Transmission Customer calculated pursuant to Section A, of this Schedule ES-3 shall be credited by an amount equal to the sum of the credits calculated for each hour of interruption or curtailment in service.

The credit to the Transmission Customer for each such hour of interruption or curtailment shall be calculated as the product of (i) the applicable equivalent hourly charge for hourly, daily, weekly, or monthly transactions, and (ii) the kilowatts of service interruption or curtailment during such hour.

5. Eversource's Annual Formula Rate for Non Firm Point-To-Point Transmission Service

Eversource's Annual Formula Rates for Non Firm Point-To-Point Transmission Service shall be expressed in $ per kilowatt-year and shall be determined in accordance with the rate formulas specified in Appendix A of this Schedule ES-3 ("Formula Rates").

6. Tax Rates and Taxes

The Formula Rates set forth in this Schedule ES-3 in effect during a Service Year shall be based on local, state, and federal tax rates and taxes in effect during the Service Year. If, at any time, additional or new taxes are imposed on Eversource or existing taxes are removed, the Formula Rate will be appropriately modified and filed with the Commission in accordance with Part 35 of the Commission's regulations.

II. In addition to the applicable charges of this Local Service Schedule, and as otherwise specified in the Service Agreement, the Transmission Customer shall pay Eversource Service each month the following additional charges for Non-firm Point-To-Point Transmission Service provided during such month.

A. Taxes and Fees Charge

B. Regulatory Expenses Charge

C. Other

A. **TAXES AND FEES CHARGE**

If any governmental authority requires the payment of any fee or assessment or imposes any form of tax with respect to payments made for Non-Firm Point-To-Point Transmission Service provided under this Local Service Schedule, not specifically provided for in any of the charge or rate provisions under this Local Service Schedule, including any applicable interest charged on any deficiency assessment made by the taxing authority, together with any further tax on such payments, the obligation to make payment for such fee, assessment, or tax shall be borne by the Transmission Customer. Eversource will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's regulations.

B. <u>**REGULATORY EXPENSES**</u>

Eversource reserves its rights to make a Section 205 filing for recovery of its costs to administer this Local Service Schedule and the Service Agreements.

C. <u>**OTHER**</u>

Eversource shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Schedule ES-3 in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE ES-3

Appendix A

CATEGORY A RATE

FOR NON-FIRM POINT-TO-POINT SERVICE

Eversource’s Category A Formula Rate for Non-Firm Point-To-Point Transmission Service ("Formula Rate") is an annual rate determined from the following formula.

$$\text{Formula Rate}_i = (A_i - B_i + C_i - D_i) / E_i$$

WHERE:

- i equals the Service Year.

- A is the annual Total Transmission Revenue Requirements (expressed in dollars) as described in Attachment ES-H.

- B is the revenues received (expressed in dollars) from the provision of transmission and other related services to others as recorded in FERC Accounts 456.1 and 454 to the extent that such transactions are not included in the determination of load (E),[2] minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

- C is the transmission payments (expressed in dollars) to the New England System Operator as recorded in FERC Account 565 in accordance with the Tariff.

- D is the sum of the annual revenues received (expressed in dollars) for the costs associated with the Localized Facilities, minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

- E is the average Eversource Monthly Transmission System Category A Load (expressed in kilowatts).

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2 Includes amortization of revenues from point-to-point transmission service provided to Consolidated Edison Energy Massachusetts, Inc. and NRG Energy, Inc. under contracts in which customers paid based on single lump sum payment.

SCHEDULE ES-3[RESERVED]

SCHEDULE ES-4

CHARGE PROVISIONS FOR LOCAL NETWORK SERVICE

I. Network Customers will pay the following demand charges for Local Network Service.

A. **DEMAND CHARGE A**

1. Determination of Demand Charge:
The Demand Charge will be determined in accordance with Section ~~16.3~~16.4 of this Local Service Schedule.

2. Eversource's Annual Transmission Revenue Requirements:
The annual Transmission Revenue Requirements shall be determined in accordance with the formula specified in Appendix A of this Schedule ES-4 ("Formula Requirements").

B. **DEMAND CHARGE B**

1. Determination of Demand Charge
The Demand Charge will be determined in accordance with Section ~~16.3~~16.4 of this Local Service Schedule.

2. Eversource Annual Transmission Revenue Requirements:
The annual Transmission Revenue Requirements for each Localized Facility of a Designated State or Area shall be determined in accordance with the formula specified in Appendix B of this Schedule ES-4 ("Formula Requirements").

C. TAX RATES AND TAXES

The Formula Requirements set forth in this Schedule ES-4 in effect during a Service Year shall be based on local, state, and federal tax rates and taxes in effect during the Service Year. If, at any time, additional or new taxes are imposed on Eversource or existing taxes are removed, the Formula Requirements will be appropriately modified and filed with the Commission in accordance with Part 35 of the Commission's regulations.

II. In addition to the applicable charges of this Local Service Schedule, and as otherwise specified in the Service Agreement, the Transmission Customer shall pay to Eversource Service each month the following additional charges for Local Network Service provided during such month.

A. Taxes and Fees Charge

B. Regulatory Expenses Charge

C. Other

A. **TAXES AND FEES CHARGE**

If any governmental authority requires the payment of any fee or assessment or imposes any form of tax with respect to payments made for service provided under this Local Service Schedule, not specifically provided for in any of the charge or rate provisions under this Local Service Schedule, including any applicable interest charged on any deficiency assessment by the taxing authority, together with any further tax on such payments, the obligation to make payment for any such fee, assessment, or tax shall be borne by the Transmission Customer. Eversource will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's regulations.

B. **REGULATORY EXPENSES CHARGE**

Eversource shall have the right to make a Section 205 filing for recovery of regulatory expenses associated with this Local Service Schedule and the Service Agreements.

C. **OTHER**

Eversource shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Schedule ES-4 in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE ES-4

Appendix A

NETWORK FORMULA REQUIREMENTS

FOR CATEGORY A COSTS

Eversource's formula requirements for Local Network Service is determined from the following formula.

$$\text{Formula Requirements}_i = A_i - B_i + C_i - D_i$$

WHERE:

- $_i$ equals the Service Year.

- A is the annual Total Transmission Revenue Requirements (expressed in dollars) as described in Attachment ES-H.

- B is the revenues received (expressed in dollars) from the provision of transmission and other related services to others as recorded in FERC Accounts 456.1 and 454 to the extent that such transactions are not included in the determination of load,[2] minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

- C is the transmission payments to (expressed in dollars) the New England System Operator as recorded in FERC Accounts 565 in accordance with the Tariff.

- D is the sum of the annual revenues received (expressed in dollars) for the costs associated with Localized Facilities, minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

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[2] Includes amortization of revenues from point-to-point transmission service provided to Consolidated Edison Energy Massachusetts, Inc. and NRG Energy, Inc. under contracts in which customers paid based on single lump sum payment.

SCHEDULE ES-4

Appendix B

NETWORK FORMULA REQUIREMENTS

FOR CATEGORY B COSTS

Eversource's formula requirements for Local Network Service and for Eligible Customers taking Regional Network Service under this Tariff in a Designated State or Area of a Localized Facility, is determined from the following formula, and separately determined for each Designated State or Area of a Localized Facility.

$$\text{Formula Requirements}_i = D_i$$

WHERE:

- $_i$ equals the Service Year.

- D is the annual Localized Transmission Revenue Requirements (expressed in dollars) of the Localized Facilities of Eversource for a Designated State or Area of a Localized Facility, as described in Attachment ES-I.

ATTACHMENT ES-C

AVAILABLE TRANSFER CAPABILITY METHODOLOGY

TABLE OF CONTENTS

1. Introduction

ISO is the regional transmission organization ("RTO"), serving the New England Control Area. ISO is responsible for the development, oversight, and fair administration of New England's wholesale market, management of the bulk electric power system and wholesale markets' planning processes. The ISO serves as the Balancing Authority for the New England Control Area. The New England Control Area is interconnected to three neighboring Balancing Authority Areas ("BAA"): New Brunswick System Operator Area ("NBSO Area"), New York Independent System Operator Area ("NYISO Area"), and Hydro-Quebec TransEnergie Area ("HQTE Area").

As part of its RTO responsibilities, the ISO is registered with the North American Electric Reliability Corporation ("NERC") as several functional model entities that have responsibilities related to the calculation of ATC as defined in the following NERC Standards: MOD-001 – Available Transmission System Capability ("MOD-001"), MOD-004 – Capacity Benefit Margin ("MOD-004"), and MOD-008 – Transmission Reliability Margin Calculation Methodology ("MOD-008"). The extent of those responsibilities is based on various Commission approved transmission operating agreements and the provisions of the ISO New England Operating Documents.

While the ISO is the Transmission Service Provider for Regional Network Service ("Regional Transmission Service") associated with Pool Transmission Facilities, the Participating Transmission Owners ("PTOs") provide local transmission service over Non-Pool Transmission Facilities within the RTO footprint and are responsible for calculating TTC and ATC associated with Local Transmission Service provided under Schedule 21 pursuant to the Transmission Operating Agreement ("TOA"). Pursuant to CFR § 37.6(b)[1] of the FERC Regulations Transmission Provider's are obligated to calculate and post TTC and ATC for each Posted Path. The ISO is not responsible for the calculation of these values.

Pursuant to the terms of the Transmission Operating Agreement executed between the companies comprising Eversource hereunder as Participating Transmission Owners ("PTOs") and ISO, Eversource is a Transmission Service Provider and calculates TTC and ATC for certain Local Facilities over which Point-to-Point transmission service is provided under Schedule 21-ES of the ISO Open Access Transmission Tariff ("ISO OATT").

[1] §37.6(b) Posting transfer capability. The available transfer capability on the Transmission Provider's system (ATC) and the total transfer capability (TTC) of that system shall be calculated and posted for each Posted Path as set out in this section.

Posted Path is defined as any control area to control area interconnection; any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a customer requests to have ATC or TTC posted. For this last category, the posting must continue for 180 days and thereafter until 180 days have elapsed from the most recent request for service over the requested path. For purposes of this definition, an hour includes any part of any hour during which service was denied, curtailed or interrupted (§37.6(b)(1)(i)).

Non-PTF facilities are primarily radial paths that provide transmission service directly to interconnected generators. It is possible, in the future that a particular path may interconnect more nameplate capacity generation than the path's TTC. However, for Eversource's Non-PTF modeled by the ISO or the Local Control Center ("LCC"), the ISO or the LCC will only dispatch an amount of generation interconnected to such path so as not to incur a reliability or stability violation on the subject path consistent with ISO's economic, security constrained dispatch methodology.

Eversource does not currently have any Posted Paths based on the above definition. However, if Eversource does have any Posted Path(s) in the future, Eversource will calculate TTC using NERC Standard MOD-029-1 Rated System Path Methodology as outlined below.

1.1 Scope of Document

The scope of this document is limited to those functions performed or utilized by Eversource as the Transmission Provider of Schedule 21-ES Local Point-to Point transmission service over Non-PTF pursuant to the PTOs' Transmission Operating Agreement and the ISO OATT:

- Total Transfer Capability (TTC) methodology
- Available Transfer Capability (ATC) methodology
- Existing Transmission Commitment (ETC)
- Use of Rollover Rights (ROR) in the calculation of ETC

As explained in Section 2, TTC and ATC are required to be calculated only for certain non-PTF internal Posted Paths over which Local Point-to-Point transmission service is provided under Schedule 21-ES. TTC and ATC is not calculated by Eversource for Local Network Service because ISO employs a market model for economic, security constrained dispatch of generation, and Eversource does not require advance reservation for such network service.

2. Transmission Service in the New England Markets

Since the inception of the OATT for New England, the process by which generation located inside New England supplies energy to the bulk electric system has differed from the Commission's pro forma OATT. The fundamental difference is that internal generation is dispatched in an economic, security constrained manner by the ISO rather than utilizing a system of physical rights, advance reservations and point-to-point transmission service. Through this process, internal generation provides offers that are utilized by the ISO in the Real-Time Energy Market dispatch software. This process provides the least-cost dispatch to satisfy Real-Time load on the system.

In addition to offers from generation within New England, entities may submit External Transactions to move energy into the ISO Area, the New England Control Area, out of the New England Control Area, or through the New England Control Area. The Real-Time Energy Market clears these External Transactions based on forecast Locational Marginal Pricing (LMPs) and the transfer capability of the associated external interfaces. With those External Transactions in place, the Real-Time Energy Market dispatches internal generation in an economic, security constrained manner to meet Real-Time load within the region.

This process for submitting External Transactions into the New England Real-Time Energy Market does not require an advance physical reservation for use of the PTF. In the event that the net of the economic External Transactions is greater than the transfer capability of the associated external interface, the External Transactions selected to flow are selected based on the rules specified in the Tariff. For any External Transactions that are confirmed to flow in Real-Time based on the economics of the system, a transmission reservation for RNS and Through or Out Service is created after-the-fact to satisfy the transparency needs of the market.

The process described above is applicable to the PTF within the ISO Area, and non-PTF Local Facilities where utilized for Local Network Service by generation or load. However, Eversource owns Local Facilities over which an advance transmission service reservation for firm or non-firm transmission service may be required. On those Local Facilities, the market participant may obtain a transmission service reservation from Eversource under Schedule 21-ES prior to delivery of energy into the New England Wholesale Market. This document addresses the calculation of ATC and TTC for these non-PTF internal paths.

3. Eversource **Total Transfer Capability (TTC)**

The Total Transfer Capability (TTC) is the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions. TTC for Schedule 21-ES is calculated using NERC Standard MOD-029-1 Rated System Path Methodology and posted on Eversource's OASIS site.

Eversource will calculate and post TTC on its OASIS site for all non-PTF Posted Paths that are eligible for Point-to-Point transmission service reservations. The TTC on Eversource's non-PTF Local Facilities that are eligible for Local Point-to-Point transmission service reservations are relatively static values. Eversource thus calculate the TTC for Non-PTF Posted Paths that may require Local Point-to-Point Local Point-to-Point transmission reservations on its OASIS provider page according to NAESB Standards.

4. Capacity Benefit Market (CBM)

CBM is defined as the amount of firm transmission transfer capability set aside by a TSP for use by the Load Serving Entities. The ISO does not set aside any CBM for use by the Load Serving Entities, because of the New England approach to capacity planning requirements in the ISO New England Operating Documents. Load Serving Entities operating within the New England Control Area are required to arrange for their Capacity Requirements prior to the beginning of any given month in accordance with ISO Tariff, Section III.13.7.3.1 (Calculation of Capacity Requirement and Capacity Load Obligation). Load Serving Entities do not utilize CBM to ensure that their capacity needs are met; therefore, CBM is not applicable within the New England market design. Accordingly, for purposes of Eversource's ATC calculation and because CBM for the New England Control Area is set to zero (0), Eversource utilizes a zero (0) CBM value.

Existing Transmission Commitments, Firm (ETC_F)

The ETC_F are those confirmed Firm transmission reservations (PTP_F) plus any rollover rights for Firm transmission reservations (ROR_F) that have been exercised. There are no allowances necessary for Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$),

grandfathered Transmission Service (GF_F) and other service(s), contract(s) or agreement(s) (OS_F) to be considered in the ETC_F calculation.

Existing Transmission Commitments, Non-Firm(ETC_{NF})

The (ETC_{NF}) are those confirmed Non-Firm transmission reservations (PTP_{NF}). There are no allowances necessary for Non-Firm Network Integration Transmission Service ($NITS_{NF}$), Non-Firm grandfathered Transmission Service (GF_{NF}) or other service(s), contract(s) or agreement(s) (OS_{NF}).

5. Transmission Reliability Margin (TRM)

TRM is the amount of transmission transfer capability set aside to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. It is used only for external interfaces under the New England market design. Eversource does not have any external interfaces, and therefore TRM for Eversource's non-PTF facilities is zero.

6. Calculation of ATC for Eversource's Local Facilities - General Description:

NERC Standards MOD-001-1 – Available Transmission System Capability and MOD-029-1 – Rated System Path Methodology define the required items to be identified when describing a transmission provider's ATC methodology. As a practical matter, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

Common practice is not to calculate or post firm and non-firm ATC values for the non-PTF assets described above, as ATC is positive and listed as 9999. Transmission customers are not restricted from reserving firm or non-firm transmission service on non-PTF facilities.

As Real-Time approaches, the ISO utilizes the Real-Time energy market rules to determine which of the submitted energy transactions will be scheduled in the coming hour. Basically, the ATC of the non-PTF assets in the New England market is almost always positive. With this simplified version of ATC, there is no detailed algorithm to be described or posted. Thus, for those non-PTF facilities that serve as a path for Eversource's Schedule 21-ES Point-to-Point Transmission Customers, Eversource has posted the ATC as 9999, consistent with industry practice. ATC on these paths varies depending on the time of day.

However, it is posted with an ATC of "9999" to reflect the fact that there are no restrictions on these paths for commercial transactions.

6.1 Calculation of Schedule 21-ES Firm ATC (ATC_F)

6.1.1 Calculation of ATC_F in the Planning Horizon (PH)

For purposes of this Attachment C PH is any period before the Operating Horizon.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for TRM, CBM, ETC_F, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM are zero. Firm Transmission Service under Schedule 21-ES that is available in the Planning Horizon (PH) includes: Yearly, Monthly, Weekly, and Daily. $Postbacks_F$ and $counterflows_F$ of Schedule 21-ES transmission reservations are not considered in the ATC calculation. Therefore, ATC_F in the PH is equal to the TTC minus ETC_F

6.1.2 Calculation of ATC_F in the Schedule 21-ES Operating Horizon (OH)

For purposes of this Attachment C OH is noon eastern prevailing time each day. At that time, the OH spans from noon through midnight of the next day for a total of 36 hours. As time progresses, the total hours remaining in the OH decreases until noon the following day when the OH is once again reset to 36 hours.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for ETC_F, CBM, TRM, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM is zero. Daily Firm Transmission Service under Schedule 21-ES is the only firm service offered in the Operating Horizon (OH). $Postbacks_F$ and $counterflows_F$ of Schedule 21-ES transmission reservations are not considered in the ATC_F calculation. Therefore, ATC_F in the OH is equal to the TTC minus ETC_F.

6.1.3 Because Firm Schedule 21-ES transmission service is not offered in the Scheduling Horizon (SH): ATC_F in the SH is zero.

6.2 Calculation of Schedule 21-ES Non-Firm ATC (ATC_{NF})

6.2.1 Calculation of ATC_{NF} in the PH

ATC_{NF} is the capability for Non-Firm transmission reservations that remain after allowing for ETC_F, ETC_{NF}, scheduled CBM (CBM_S), unreleased TRM (TRM_U), Non-Firm Postbacks ($Postbacks_{NF}$) and Non-Firm counterflows ($counterflows_{NF}$).

As discussed above, the TRM and CBM for Schedule 21-ES are zero. Non-Firm ATC available in the PH includes: Monthly, Weekly, Daily and Hourly. TRM_U, $Postbacks_{NF}$ and $counterflows_{NF}$ of Schedule 21-ES transmission reservations are not considered in this calculation. Therefore, ATC_{NF} in the PH is equal to the TTC minus ETC_F and ETC_{NF}.

6.2.2 Calculation of ATC_{NF} in the OH

ATC_{NF} available in the OH includes: Daily and Hourly.

As discussed above TRM and CBM for Schedule 21-ES are zero. TRM_U, counterflows and ETC_{NF} are not considered in this calculation. Therefore, ATC_{NF} in the OH is equal to the TTC minus ETC_F, plus postbacks of PTP_F in OH as PTP_{NF} ($Postbacks_{NF}$)

6.3 Negative ATC

As stated above, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

As stated above, Eversource's non-PTF facilities are primarily radial paths that provide transmission service to directly interconnected generators. It is possible, in the future, that a particular radial path may interconnect more nameplate capacity generation than the path's TTC. However, due to the ISO's security constrained dispatch methodology, the ISO will only dispatch an amount of generation interconnected to such path so as not to incur a reliability or stability violation on the subject path. Therefore, ATC in the PH, OH and SH may become zero, but will not become negative.

7. Posting of Schedule 21-ES ATC

7.1 Location of ATC Posting

ATC values are posted on Eversource's OASIS site.

7.2 Updates To ATC

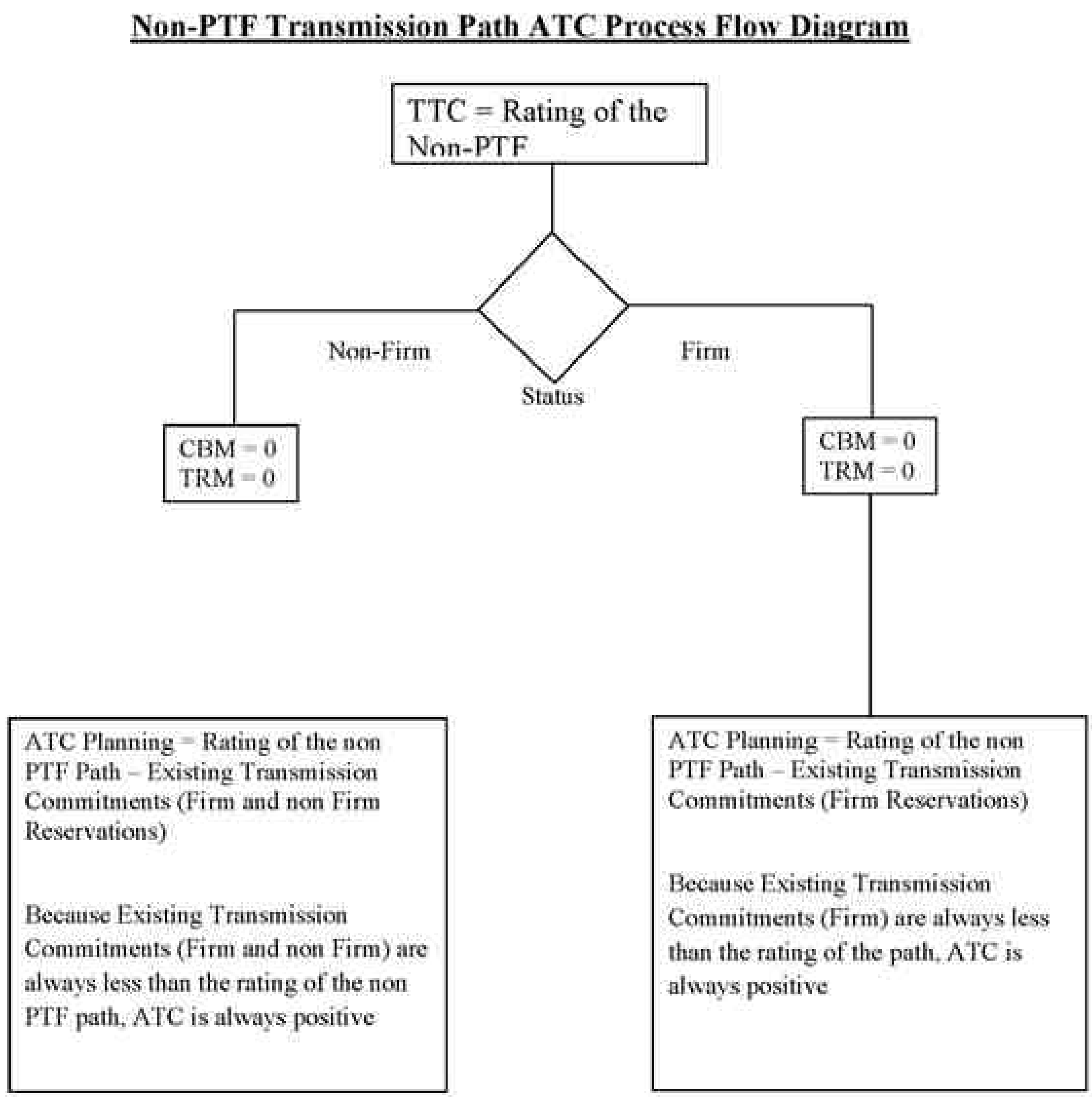
When any of the variables in the ATC equations change, the ATC values are recalculated and immediately posted.

7.3 Coordination of ATC Calculations

Schedule 21-ES non-PTF has no external interfaces. Therefore it is not necessary to coordinate the values.

7.4 Mathematical Algorithms A link to the actual mathematical algorithm for the calculation of ATC for the Eversource non-PTF internal interfaces is located at https://www.eversource.com/Content/docs/default-source/Tranmission/attachment-6.pdf?sfvrsn=0.

8. Process Flow Diagram for ATC Calculation



ATTACHMENT ES-D

PENALTY DISBURSEMENT METHODOLOGY

Late Study Penalties: Penalties paid by the Transmission Provider pursuant to Schedule 21 are referred to as "Late Study Penalties," and therefore subject to distribution to all Transmission Customers that are not affiliated with the Transmission Provider. On the month following the end of each calendar quarter, each Transmission Customer that is not affiliated with the Transmission Provider shall receive, on the relevant monthly invoice, a credit for its share of the Late Study Penalties that were assessed during the applicable calendar quarter. The Transmission Customer's share of the Late Study Penalties (if any) will be determined as follows:

(a) For each quarter, the Transmission Provider will determine: (1) the sum of all Late Study Penalties assessed during the quarter measured in dollars (LSRq), and (2) the sum of all transmission revenue from Transmission Customers that are not affiliated with the Transmission Provider during that quarter, measured in dollars (LSTRq). Where:

LSRq =	Late Study Penalty Revenue in the quarter
LSTRq =	Transmission Revenue from Transmission Customers not affiliated with the Transmission Provider in the quarter

(b) For each quarter, each Transmission Customer that was not affiliated with the Transmission Provider will receive a credit equal to the product of (i) LSRq multiplied by (ii) a fraction derived from dividing the amount of transmission revenue from that Transmission Customer (TC1) during that quarter (measured in dollars), where TC1 is equal to one Transmission Customer, and a denominator equal to LSTRq.

(c) The Transmission Provider shall apply the credit for Late Study Penalties to service that the non-affiliated Transmission Customer takes from the Transmission Provider pursuant to this Schedule 21-ES. Any remaining credit will be refunded to the Transmission Customer.

ATTACHMENT ES-E

LOCALIZED COSTS RESPONSIBILITY **AGREEMENT**

This Localized Costs Responsibility Agreement ("LCRA" or "Agreement"), dated as of _______________________, is entered into by and between the Eversource Energy Service Company ("Eversource Service" or "COMPANY"), acting as agent for [The Connecticut Light and Power Company, Western Massachusetts Electric Company, Public Service Company of New Hampshire], andthe "Transmission Customer".

The Transmission Customer is _____________________________________. The Transmission Customer has been determined to be an Eligible Customer taking Regional Network Service under the Tariff whose load **is located in the** Designated State or Area for a **Localized** Facility listed in **Section** 16.3 **of** Schedule 21-ES of the Tariff**.**

The Transmission Customer agrees to pay its portion of the cost of Localized Facilities in the Designated State or Area in which the Transmission Customer's load is located as provided in the Tariff and in accordance with Commission orders. Billing under this Agreement shall commence on the later of: (1) 0001 hours on _____________________, or (2) such other date as permitted by the Commission.

Charges under this Agreement shall terminate on the earlier of: (1) the date on which the costs of the Localized Facilities in the Designated State or Area in which the Transmission Customer's load is located are fully depreciated; or (2) the date upon which the Transmission Customer no longer takes Regional Network Service under the Tariff in the Designated State or Area in which the Transmission Customer's load is located; provided, that the Transmission Customer shall remain responsible for all final payment obligations. In the event that the Transmission Customer sells or assigns, or transfers its load to another entity ("New Transmission Customer"), the Transmission Customer must provide Eversource Service with at least ninety (90) calendar days advance written notice of the sale, assignment, or transfer.

The Transmission Customer shall remain liable for the performance of all obligations under this Agreement until a new LCRA has been executed between the New Transmission Customer and Eversource Service, or in the case of an unexecuted LCRA, such other date as it has been **permitted to** be made effective by the Commission. No sale or assignment shall **become effective** until the Parties have complied with all Applicable Laws and Regulations required for such sale, assignment, or transfer**.**

Other special provisions (if any)
____.

Any notice or request made to or by any Party regarding this greement shall be made in writing and shall be telecommunicated or delivered either in person, or by prepaid mail (return receipt requested) to the representative of the other Party as indicated below. Such representative and address for notices or requests may be changed from time to time by notice by one Party to the other.

COMPANY:
____
____
____

TRANSMISSION CUSTOMER:
____
____
____

Any exhibits to thisAgreement and the Tariff are incorporated herein and made a part hereof. ThisAgreement may be amended, from time to time, as provided for in Schedule 21-ES of the Tariff.

IN WITNESS WHEREOF, the Parties have caused thisAgreement to be executed by their respective authorized officials as of the date first above written.

EVERSOURCE ENERGY SERVICE COMPANY
By: _____________________________________
Its _________________________

TRANSMISSION CUSTOMER
By**:** ___________________________________
Its _____________________________________

ATTACHMENT ES-G
NETWORK OPERATING AGREEMENT

This Network Operating Agreement is an appendix to Schedule 21-ES (this Local Service Schedule) of the OATT and operates as an implementing agreement for Local Network Service under this Local Service Schedule. This Network Operating Agreement is subject to and in accordance with Part III of this Local Service Schedule. All definitions and other terms and conditions of this Local Service Schedule are incorporated herein by reference.

1.0 Definitions:

1.1 Data Acquisition Equipment

Supervisory control and data acquisition ("SCADA"), remote terminal units ("RTUs") to obtain information from a Party's facilities, telephone equipment, leased telephone circuits, fiber optic circuits, and other communications equipment necessary to transmit data to remote locations, and any other equipment or service necessary to provide for the telemetry and control requirements of this Local Service Schedule.

1.2 Data Link

The direct communications link between the Transmission Customer's energy control center and Eversource's designated location(s) that will enable Eversource to receive real time telemetry and data from the Transmission Customer.

1.3 Metering Equipment

High accuracy, solid state kW, kVAR, kWh meters, metering cabinets, metering panels, conduits, cabling, high accuracy current transformers and high accuracy potential transformers, which directly or indirectly provide input to meters or transducers, metering recording devices, telephone circuits, signal or pulse dividers, transducers, pulse accumulators, metering sockets, test switch devices, enclosures, conduits, and any other metering, telemetering or communication equipment necessary to implement the provisions of this Local Service Schedule.

1.4 Protective Equipment

Protective relays, relaying panels, relaying cabinets, circuit breakers, conduits, cabling, current transformers, potential transformers, coupling capacitor voltage transformers, wave traps, transfer trip and

fault recorders, which directly or indirectly provide input to relays, fiber optic communication equipment, power line carrier equipment and telephone circuits, and any other protective equipment necessary to implement the protection provision of this Local Service Schedule.

2.0 Term

The term shall be as provided in the Service Agreement consistent with this Local Service Schedule (including, but not limited to, application procedures, commencement of service, and effect of termination).

3.0 Point(s) Of Interconnection

Local Network Service will be provided by Eversource at the point(s) of interconnection specified in Appendix __, as amended from time to time. Each point of interconnection in this listing shall have a unique identifier, meter location, meter number, metered voltage, terms on meter compensation and designation of current or future year of in service.

4.0 Cogeneration And Small Power Production Facilities

If a Qualifying Facility is located or locates in the future on the System of the Transmission Customer, and the owner or operator of such Qualifying Facility sells the output of such Qualifying Facility to an entity other than the Transmission Customer, the delivery of such Qualifying Facility's power shall be subject to and contingent upon transmission arrangements being established with Eversource prior to commencement of delivery of any such power and energy.

5.0 Character Of Service

Network Transmission Service at the points of interconnection shall be in the form of single phase or balanced three-phase alternating current at a frequency of sixty (60) hertz. The Transmission Customer shall operate and maintain its electric system in a manner that avoids: (i) the generation of harmonic frequencies exceeding the limits established by the latest revision of IEEE-519; (ii) voltage flicker exceeding the limits established by the latest revision of IEEE-141; (iii) negative sequence currents; (iv) voltage or current fluctuations; (v) frequency variations; or (vi) voltage or power factor levels that could adversely affect Eversource’s electrical equipment or facilities or those of its customers, and in a manner that complies with all applicable NERC, NPCC, ISO and Eversource’s operating criteria, rules, regulations, procedures, guidelines and interconnection standards as amended from time to time.

6.0 Continuity Of Service

(a) Eversource and the Transmission Customer shall operate and maintain their respective network systems, in accordance with Good Utility Practice, and in a manner that will allow Eversource to safely and reliably operate the Eversource Transmission System in accordance with this Local Service Schedule, so that either Party shall not unduly burden the other Party; provided, however, that notwithstanding any other provision of this Local Service Schedule, Eversource shall retain the sole responsibility and authority for all operating decisions that could affect the integrity, reliability and security of the Eversource Transmission System.

(b) Eversource shall exercise reasonable care and Due Diligence to ensure Local Network Service hereunder in accordance with Good Utility Practice; provided, however, that Eversource shall not be responsible for any failure to ensure electric power service, nor for interruption, reversal or abnormal voltage of the service, if such failure, interruption, reversal or abnormal voltage is due to a Force Majeure.

7.0 Power Factor

(a) Where Local Network Service provided under this Local Service Schedule is for delivery of power to a load center of the Transmission Customer served from the Eversource Transmission System, the Transmission Customer shall maintain load power factor levels, during both on- and off- peak hours, appropriate to meet the operating requirements of Eversource, and shall follow the ISO standards and practices, as set forth in the Service Agreement.

(b) Where Local Network Service provided under this Local Service Schedule is for delivery of power from a generating facility connected to the Eversource Transmission System, the Transmission Customer shall deliver power at a lagging or leading power factor as set forth in the Service Agreement.

(c) Where Local Network Service provided under this Local Service Schedule is for delivery of power from outside the Eversource Transmission System, the obligation to maintain proper sending and receiving end voltages rests with the Transmission Customer, as set forth in the Service Agreement.

(d) In the event that the power factor levels and reactive supply requirements set forth in the Service Agreement are not maintained by the Transmission Customer, Eversource shall thereupon have the right to take the appropriate corrective action and to charge the Transmission Customer for the costs thereof.

Eversource shall have the right, at any time, unilaterally to make a Section 205 filing with the Commission for the recovery of any such costs.

8.0 Metering

(a) The Transmission Customer shall, at its expense, purchase all necessary metering equipment to accurately account for the electric power being transmitted under this Local Service Schedule. Eversource may require the installation of telemetering equipment for the purposes of billing, power factor measurements and to allow Eversource to maximize economic and reliable operation of its transmission system. Such metering equipment shall meet the specifications and accepted metering practices of Eversource and applicable criteria, rules, standards and operating procedures, or such successor rules and standards. At Eversource’s option, communication metering equipment may be installed in order to transmit meter readings to Eversource’s designated locations.

(b) Electric power being transmitted under this Local Service Schedule will be measured by meters at all points of interconnection and/or on generating facilities (Network and non-Network Resources) located on and outside the Transmission Customer's system as required by Eversource.

(c) The Transmission Customer shall purchase meters capable of time-differentiated (by hour) measurement of the instantaneous flow in kW and net active power flow in kWh and of reactive power flow. All meters shall compensate for applicable line and/or transformer losses in accordance with Good Utility Practice when measurement is made at any location other than the point of interconnection.

(d) Eversource reserves the right: (i) to determine metering equipment ownership; (ii) to determine the equipment installation at each point of interconnection; (iii) to require the Transmission Customer to install the equipment -- or -- install the equipment with the Transmission Customer supplying without cost to Eversource a suitable place for the installation of such equipment; (iv) to determine other equipment allowed in the metering circuit; (v) to determine metering accuracy requirements; (vi) to determine the responsibilities for operation, maintenance, testing and repair of metering equipment.

(e) Eversource shall have access to metering data, including telephone line access, which may reasonably be required to facilitate measurement and billing under this Local Service Schedule. Eversource may require the Transmission Customer provide, at its expense, a separate dedicated voice grade telephone circuit for Eversource and the Transmission Customer to remotely access each meter.

Metering equipment and data shall be accessible at all reasonable hours for purposes of inspection and reading.

(f) All metering equipment shall be tested in accordance with practices of Eversource, applicable criteria, rules, standards and operating procedures or upon the request by Eversource. If at any time metering equipment fails to register or is determined to be inaccurate, in accordance with Eversource's practices and applicable criteria, rules, standards and operating procedures, the Transmission Customer shall make the equipment accurate as soon thereafter as practicable, and the meter readings and rate computation for the period of such inaccuracy, insofar as can reasonably be ascertained, shall be adjusted; provided, however, that no adjustment to charges shall be required for any period exceeding two (2) months prior to the date of the test. Representatives of Eversource will be afforded opportunity to witness such tests.

9.0 Network Load

The Transmission Customer shall provide Eversource with the actual hourly Network Load for each calendar month by the seventh day of the following calendar month.

10.0 Data Transfer:

(a) The Transmission Customer shall provide timely, accurate real time information to Eversource in order to facilitate performance of its obligations under this Local Service Schedule.

(b) The selection of real time telemetry and data to be received by Eversource and the Transmission Customer shall be necessary for safety, reliability, security, economics, and/or monitoring of real-time conditions that affect the Eversource Transmission System. This telemetry shall include, but is not limited to, loads, line flows (MW and MVAR), voltages, generator output, and status of substation equipment at any of the Transmission Customer's transmission and generation facilities. To the extent that Eversource or the Transmission Customer requires data that are not available from existing equipment, the Transmission Customer shall, at its expense and at locations designated by Eversource or the Transmission Customer, install any metering equipment, data acquisition equipment, or other equipment and software necessary for the telemetry to be received by Eversource or the Transmission Customer. Eversource shall have the right to inspect equipment and software associated with the data transfer in order to assure conformance with Good Utility Practices.

11.0 Maintenance of Equipment

The Transmission Customer shall, on a regular basis in accordance with practices of Eversource, applicable criteria, rules, standards and operating procedures or at the request of Eversource, and at its expense, test, calibrate, verify and validate the data link, metering equipment, data acquisition equipment, transmission equipment, protective equipment and other equipment or software used to implement the provisions of this Local Service Schedule. Eversource shall have the right to inspect such tests, calibrations, verifications and validations of the data link, metering equipment, data acquisition equipment, transmission equipment, protective equipment and other equipment or software used to implement the provisions of this Local Service Schedule. Upon Eversource’s request, the Transmission Customer will provide Eversource a copy of the installation, test and calibration records of the data link, metering equipment, data acquisition equipment, transmission equipment, protective equipment and other equipment or software. Eversource shall, at the Transmission Customer's expense, have the right to monitor the factory acceptance test, the field acceptance test, and the installation of any metering equipment, data acquisition equipment, transmission equipment, protective equipment and other equipment or software used to implement the provisions of this Local Service Schedule.

12.0 Notification

(a) The Transmission Customer shall notify and coordinate with Eversource prior to the commencement of any work or maintenance by the Transmission Customer, Network Member, or contractors or agents performing on behalf of either or both, which may directly or indirectly have an adverse effect on the Transmission Customer or Eversource’s data link, or the reliability of the Eversource Transmission System. All notifications for scheduled outages of the data link, metering equipment, data acquisition equipment, transmission equipment, protective equipment and other equipment or software must meet the requirements of the ISO and Eversource.

13.0 Emergency System Operations

(a) The Transmission Customer, at its expense, shall be subject to all applicable emergency operation standards promulgated by NERC, NPCC, ISO and Eversource which may include but not limited to underfrequency relaying equipment, load shedding equipment and voltage reduction equipment.

(b) Eversource reserves the right to take whatever actions they deem necessary to preserve the integrity of the Eversource Transmission System during emergency operating conditions. If the Local Network Service at the points of interconnection is causing harmful physical effects to the Eversource

Transmission System facilities or to its customers (e.g., harmonics, undervoltage, overvoltage, flicker, voltage variations, etc.), Eversource shall promptly notify the Transmission Customer and if the Transmission Customer does not take the appropriate corrective actions immediately, Eversource shall have the right to interrupt Local Network Service under this Local Service Schedule in order to alleviate the situation and to suspend all or any portion of Local Network Service under this Local Service Schedule until appropriate corrective action is taken.

(c) In the event of any adverse condition or disturbance on the Eversource Transmission System or on any other system directly or indirectly interconnected with the Eversource Transmission System, Eversource may, as it deems necessary, take actions or inactions that, in Eversource's sole judgment, result in the automatic or manual interruption of Local Network Service in order to: (i) limit the extent or damage of the adverse condition or disturbance; (ii) prevent damage to generating or transmission facilities; (iii) expedite restoration of service; or (iv) preserve public safety.

14.0 Cost Responsibility

(a) The Transmission Customer shall be responsible for the costs incurred by the Transmission Customer and Eversource to implement the provisions of this Local Service Schedule including, but not limited to, engineering, administrative and general expenses, material and labor expenses associated with the specifications, design, review, approval, purchase, installation, maintenance, modification, repair, operation, replacement, checkouts, testing, upgrading, calibration, removal, and relocation of equipment, or software.

(b) Additionally, the Transmission Customer shall be responsible for all costs incurred by the Transmission Customer and Eversource for on-going operation and maintenance of the metering, telecommunications and safety protection facilities and equipment required to implement the provisions of this Local Service Schedule. Such work shall include, but not limited to, normal and extraordinary engineering, administrative and general expenses, material, and labor expenses associated with the specifications, design, review, approval, purchase, installation, maintenance, modification, repair, operation, replacement, checkouts, testing, upgrading, calibration, removal, or relocation of equipment required to accommodate service under this Local Service Schedule.

15.0 Default

The Transmission Customer's failure to implement the terms and conditions of this Network Operating Agreement will be deemed to be a default under this Local Service Schedule and will result in Eversource seeking, consistent with FERC rules and regulations, immediate termination of service under this Local Service Schedule.

16.0 Regulatory Filings

Nothing contained in this Local Service Schedule or any associated Service Agreement, including this Network Operating Agreement, shall be construed as affecting in any way the right of Eversource to unilaterally make application to the Commission for a change in any portion of this Network Operating Agreement under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

IN WITNESS WHEREOF, the Parties have caused this Network Operating Agreement to be executed by their respective authorized officials as of the date written.

Date: ___________________________

<u>Eversource Energy Service Company</u>
by: ________________________________
its Vice President

<u>Transmission Customer</u>
by: ________________________________
its ________________________________

ATTACHMENT ES-H

ANNUAL TRANSMISSION REVENUE REQUIREMENTS

Attachment ES-H Methodology:

This formula sets forth the method that Eversource will use to determine its annual Total Transmission Revenue Requirements. The Transmission Revenue Requirements reflect Eversource's total cost to own, operate and maintain the transmission facilities used for providing Open Access Transmission Service to transmission customers under this Local Service Schedule. The Transmission Revenue Requirements will be an annual formula rate calculation, effective for an initial term commencing on the effective date established by FERC and ending on May 31 of the following year. The calculation will be based on the previous calendar year's FERC Form 1 data, with an estimate of Eversource's current year average plant additions, Construction Work in Progress (CWIP), and the Allowance for Funds Used During Construction (AFUDC) regulatory liability account. Plant additions will be multiplied by a fixed charge carrying cost, and CWIP and the AFUDC regulatory liability account will be multiplied by the Cost of Capital. The revenue requirements will be updated thereafter each June 1 based on actual costs from the Service Year. The true-up information will be based on actual data, in lieu of allocated data if specifically identified in the FERC Form 1. For a capital addition whose cost exceeds $20 million, Eversource will make rate base adjustments to estimates and in the true-up process to represent the estimated and actual in-service dates for the capital addition. Specifically, Eversource will adjust for transmission plant, CWIP, AFUDC regulatory liability, accumulated depreciation and accumulated deferred taxes.

I. Definitions

Capitalized terms not otherwise defined in the Tariff and as used in this formula have the following definitions:

A. Allocation Factors

1. <u>Transmission Wages and Salaries Allocation Factor</u> shall equal the ratio of Eversource's Transmission-related direct wages and salaries, including those of affiliated companies, to Eversource's total direct wages and salaries, including those of affiliated companies, excluding administrative and general wages and salaries.

2. Plant Allocation Factor shall equal the ratio of the sum of total investment in Transmission Plant and Transmission Related General Plant to Total Plant in Service.

B. Terms

Administrative and General Expense shall equal Eversource's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928 and 930.1 and excluding Merger-Related Costs included in FERC Account Nos. 920-935 (other than those in FERC Account Nos. 924, 928 and 930.1, which have already been excluded).

AFUDC Regulatory Liability shall equal the unamortized balance of the capitalized AFUDC booked on Eversource's transmission projects as recorded in FERC Account 254 consistent with Commission orders.

Amortization of Loss on Reacquired Debt shall equal Eversource's expenses as recorded in FERC Account No. 428.1.

Amortization of Investment Tax Credits shall equal Eversource's credits as recorded in FERC Account No. 411.4.

Depreciation Expense for Transmission Plant shall equal Eversource's transmission expense as recorded in FERC Account No. 403.

Dispatch Center means CL&P's CONVEX dispatch center.

Dispatch Center Plant shall equal CL&P's gross plant balance for the Dispatch Center as recorded in FERC Account Nos. 350-359 and 389-399.

Dispatch Center Depreciation Expense shall equal the Dispatch Center depreciation expense as recorded in FERC Account No. 403.

Dispatch Center Amortization of Investment Tax Credits shall equal the Dispatch Center amortization of investment tax credits as recorded in FERC Account No. 411.4.

D<u>ispatch Center Accumulated Deferred Income Taxes</u> shall equal the net of Eversource’s Dispatch Center deferred tax balance as recorded in FERC Account Nos. 281-283 and Eversource’s Dispatch Center deferred tax balance as recorded in FERC Account No. 190.

<u>Dispatch Center Municipal Tax Expense</u> shall equal the Dispatch Center municipal tax expense as recorded in FERC Account Nos. 408.1 and 409.1.

<u>General Plant</u> shall equal Eversource’s gross plant balance as recorded in FERC Account Nos. 389-399, less the Dispatch Center general plant.

<u>General Plant Depreciation Expense</u> shall equal Eversource’s general plant expenses as recorded in FERC Account No. 403.

<u>General Plant Depreciation Reserve</u> shall equal Eversource’s general plant reserve balance as recorded in FERC Account No. 108 less the portion of such reserve for the Dispatch Center.

<u>Merger-Related Costs shall equal Eversource’s amortized merger-related costs as authorized by FERC or by state regulatory order.</u>

<u>Other Regulatory Assets/Liabilities</u> – FAS 106 shall equal the net of Eversource’s FAS 106 balance as recorded in FERC Account No. 182.3 and any FAS 106 balance as recorded in Eversource’s FERC Account No. 254.

<u>Other Regulatory Assets/Liabilities</u> – FAS 109 shall equal the net of Eversource’s FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in Eversource’s FERC Account No. 254.

<u>Payroll Taxes</u> shall equal those payroll expenses as recorded in Eversource’s FERC Account Nos. 408.1 and 409.1.

<u>Plant Held for Future Use</u> shall equal Eversource’s balance in FERC Account No. 105.

<u>Prepayments</u> shall equal Eversource’s prepayment balance as recorded in FERC Account No. 165.

<u>Property Insurance</u> shall equal Eversource’s expenses as recorded in FERC Account No. 924.

Total Accumulated Deferred Income Taxes shall equal the net of Eversource's deferred tax balance as recorded in FERC Account Nos. 281-283 and Eversource's deferred tax balance as recorded in FERC Account No. 190.

Total Loss on Reacquired Debt shall equal Eversource's expenses as recorded in FERC Account 189.

Total Municipal Tax Expense shall equal Eversource's expenses as recorded in FERC Account Nos. 408.1, 409.1.

Total Plant in Service shall equal Eversource's total gross plant balance as recorded in FERC Account Nos. 301-399.

Total Transmission Depreciation Reserve shall equal Eversource's Transmission reserve balance as recorded in FERC Account 108 less the portion of such reserve for the Dispatch Center.

Transmission Merger-Related Costs shall equal Eversource's amortized merger-related transmission costs as authorized by FERC.

Transmission Operation and Maintenance Expense shall equal Eversource's expenses as recorded in FERC Account Nos. 560, 561.5 – 561.8, 562-564 and 566-576.5 and shall exclude all HQ HVDC expenses booked to accounts 560 through 576.5 and expenses already included in Transmission Support Expense, as described in Section I below, that are included in FERC Account Nos. 560-576.5.

Transmission Plant shall equal Eversource's gross plant balance as recorded in FERC Account Nos. 350-359, less Dispatch Center transmission plant.

Transmission Plant Materials and Supplies shall equal Eversource's balance as assigned to transmission, as recorded in FERC Account 154.

Transmission Related Construction Work in Progress shall equal Eversource's investment in Transmission-related projects as recorded in FERC Account 107 consistent with commission orders.

II. Calculation of Transmission Revenue Requirements

The Transmission Revenue Requirement shall equal the sum of Eversource's (A) Return and Associated Income Taxes, (B) Transmission Depreciation Expense, (C) Transmission Related Amortization of Loss on Reacquired Debt, (D) Transmission Related Amortization of Investment Tax Credits, (E) Transmission Related Municipal Tax Expense, (F) Transmission Related Payroll Tax Expense, (G) Transmission Operation and Maintenance Expense, (H) Transmission Related Administrative and General Expense (I) Transmission Support Expense, and(J) Transmission Related Taxes and Fees Charge.

A. <u>Return and Associated Income Taxes</u> shall equal the product of the Transmission Investment Base and the Cost of Capital Rate.

1. <u>Transmission Investment Base</u>

The Transmission Investment Base will be the average balances of (a) Transmission Plant, plus (b) Transmission Related General Plant, plus (c) Transmission Plant Held for Future Use, plus (d) Transmission Related Construction Work in Progress, less (e) Transmission Related Depreciation Reserve, less (f) Transmission Related Accumulated Deferred Taxes, plus (g) Transmission Related Loss on Reacquired Debt, plus (h) Other Regulatory Assets/Liabilities, less (i) AFUDC Regulatory Liability, plus (j) Transmission Prepayments, plus (k) Transmission Materials and Supplies, plus (l) Transmission Related Cash Working Capital.

(a) <u>Transmission Plant</u> will equal the balance of Eversource's investment in Transmission Plant.

(b) <u>Transmission Related General Plant</u> shall equal Eversource's balance of investment in General Plant multiplied by the Transmission Wages and Salaries Allocation Factor.

(c) <u>Transmission Plant Held for Future Use</u> shall equal the balance of Transmission Plant Held for Future Use.

(d) <u>Transmission Related Construction Work in Progress</u> shall equal the portion of Eversource's investment in Transmission-related projects as recorded in FERC Account 107 consistent with Commission orders.

(e) <u>Transmission Related Depreciation Reserve</u> shall equal the balance of Total Transmission Depreciation Reserve, plus the balance of Transmission Related General Plant

Depreciation Reserve. Transmission Related General Plant Depreciation Reserve shall equal the product of General Plant Depreciation Reserve and the Transmission Wages and Salaries Allocation Factor.

(f) Transmission Accumulated Deferred Taxes shall equal Eversource's electric balance of Total Accumulated Deferred Income Taxes multiplied by the Plant Allocation Factor, less the transmission and general plant components of Dispatch Center Accumulated Deferred Income Taxes.

(g) Transmission Related Loss on Reacquired Debt shall equal Eversource's electric balance of Total Loss on Reacquired Debt multiplied by the Plant Allocation Factor.

(h) Other Regulatory Assets/Liabilities shall equal Eversource's electric balance of any deferred rate recovery of FAS 106 expense multiplied by the Transmission Wages and Salaries Allocation Factor, plus Eversource's electric balance of FAS 109 multiplied by the Plant Allocation Factor.

(i) AFUDC Regulatory Liability shall equal the unamortized balance of the capitalized AFUDC booked on Eversource's transmission projects as recorded in FERC Account 254 consistent with Commission orders.

(j) Transmission Prepayments shall equal Eversource's electric balance of Prepayments multiplied by the Transmission Wages and Salaries Allocation Factor.

(k) Transmission Materials and Supplies shall equal Eversource's electric balance of Transmission Plant Materials and Supplies.

(l) Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Transmission Operation and Maintenance Expense and Transmission Related Administrative and General Expense.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) Eversource's Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon the capital structure at the end of each year and will equal the sum of:

(i) the long term debt component, which equals the product of the actual weighted average embedded cost to maturity of Eversource's long-term debt then outstanding and the ratio that long-term debt is to Eversource's total capital.

(ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of Eversource's preferred stock then outstanding and the ratio that preferred stock is to Eversource's total capital.

(iii) the return on equity component, shall equal the product of Eversource's return on equity ("ROE") of 10.57% and the ratio that common equity is to Eversource's total capital.

(b) Federal Income Tax shall equal

[(A+[(C+B)/D]x (FT)] divided by (1-FT)

where FT is the Federal Income Tax Rate and A is the sum of the preferred stock component and the return on equity component, as determined in Sections II.A.2.(a)(ii) and (iii) above, B is Transmission Related Amortization of Investment Tax Credits, as determined in Section II.D., below, C is the Equity AFUDC component of Transmission Depreciation Expense, as defined in Section II.B., and D is Transmission Investment Base, as Determined in II.A.1., above.

(c) State Income Tax shall equal

[A+[(C+B)/D] + Federal Income Tax)x(ST)] divided by (1-ST)

where ST is the State Income Tax Rate, A is the sum of the preferred stock component and return on equity component determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section II.D. below, C is the equity AFUDC component of Transmission Depreciation Expense, as defined in Section II.B., D is the

Transmission Investment Base, as determined in II.A.1., above and Federal Income Tax is the rate determined in Section II.A.2.(b) above.

B. Transmission Depreciation Expense shall equal the sum of Depreciation Expense for Transmission Plant, plus an allocation of General Plant Deprecation Expense calculated by multiplying General Plant Depreciation Expense by the Transmission Wages and Salaries Allocation Factor, less the amortization of AFUDC Regulatory Credit as recorded in Account 407.4, less the transmission plant and general plant components of Dispatch Center Depreciation Expense.

C. Transmission Related Amortization of Loss on Reacquired Debt shall equal Eversource's electric Amortization of Loss on Reacquired Debt multiplied by the Plant Allocation Factor.

D. Transmission Related Amortization of Investment Tax Credits shall equal Eversource's electric Amortization of Investment Tax Credits multiplied by the Plant Allocation Factor less the transmission plant and general plant components of Dispatch Center Amortization of Investment Tax Credits.

E. Transmission Related Municipal Tax Expense shall equal Eversource's electric Total Municipal Tax Expense multiplied by the Plant Allocation Factor, less the transmission plant and general plant components of Dispatch Center Municipal Tax Expense.

F. Transmission Related Payroll Tax Expense shall equal Eversource's electric Payroll Tax expense, multiplied by the Transmission Wages and Salaries Allocation Factor.

G. Transmission Operation and Maintenance Expense shall equal Transmission Operation and Maintenance Expenses.

H. Transmission Related Administrative and General Expenses shall equal the sum of (1) Eversource's Administrative and General Expenses multiplied by the Transmission Wages and Salaries Allocation Factor, (2) Property Insurance multiplied by the Transmission Plant Allocation Factor, (3) Expenses included in Account 928 (excluding Merger-Related Costs included in Account 928) related to FERC Assessments multiplied by the Plant Allocation Factor, plus any other Federal and State transmission related expenses or assessments in Account 928 plus specific transmission related expenses included in Account 930.1, plus Transmission Merger-Related Costs and, (4) specific transmission related public education expenses included in Account 426.54.

I. Transmission Support Expense shall equal the expense paid by Eversource for transmission support.

J. Transmission Related Taxes and Fees Charge shall include any fee or assessment imposed by any governmental authority on service provided under this Local Service Schedule that is not specifically identified under any other section of this Local Service Schedule.

ATTACHMENT ES-I

ANNUAL LOCALIZED TRANSMISSION REVENUE REQUIREMENT

Attachment ES-I Methodology

This formula sets forth the method that Eversource will use to determine its annual total revenue requirements for each Localized Facility ("Localized Transmission Revenue Requirement"). Subsequent references in this formula to "Localized Facility" and "Localized Transmission Revenue Requirement" refer to the Localized Facility and Localized Facility Revenue Requirement for each individual Localized Transmission Project. Each Localized Facility is identified in Section 16.3.

The Localized Transmission Revenue Requirement will be calculated for an initial term for a Localized Facility commencing on the date of the New England System Operator's Schedule 12C cost allocation determination for the Localized Facility and ending on the May 31st following the date approved by the Commission for including the costs of the Localized Facilities in this Attachment ES-I ("Initial Term"), and continuing thereafter for successive 12 month periods commencing each June 1st ("Rate Year"). The Localized Transmission Revenue Requirement for the Initial Term for a Localized Facility will be calculated based on the estimated cost of the Localized Facilities for such period, and will be charged to customers in equal monthly installments beginning on the date permitted by the Commission, and continuing through the end of the Initial Term. The Localized Transmission Revenue Requirement for the Initial Term for a Localized Facility will be trued up for the appropriate calendar year by June 30th of the succeeding year(s) based on actual costs for the Initial Term.

The Localized Transmission Revenue Requirement for a Localized Transmission Project for a Rate Year commencing after the Initial Term (and for succeeding Rate Years) will be an annual calculation based on the previous calendar year's Localized Transmission Revenue Requirements, plus the forecasted revenue requirements of Localized Facilities to be placed in service in the upcoming Rate Year. Each June 30th,

the Localized Transmission Revenue Requirement in effect during the portion of the Rate Year that occurred in the previous calendar year will be trued-up based on actual costs from such previous calendar year.

The true-up information will be based on actual data, in lieu of allocated data if specifically identified in the FERC Form 1, or based on allocated data if such specific information is not identified. For a capital addition whose cost exceeds $20 million, Eversource will make rate base adjustments to estimates and in the true-up process to represent the estimated and actual in-service dates for the capital addition. Specifically, Eversource will adjust for transmission plant, accumulated depreciation and accumulated deferred taxes.

The Localized Transmission Revenue Requirement for Eversource that is based on data for calendar year 2004 or later shall include a Localized Incremental Return and Associated Income Taxes on Eversource's Localized PTF transmission plant investments placed in-service on or after January 1, 2004 (such investments referred to herein as "Localized Post-2003 PTF Investment"). The Localized Incremental Return and Associated Income Taxes for Localized Post-2003 Investment shall incorporate an incentive ROE adder of 100 basis points for plant investments placed in service by December 31, 2008 or as otherwise permitted in Docket Nos. ER04-157 et al. for any projects included in the Regional System Plan ("RSP"), and shall incorporate any incentive ROE adder approved by the FERC under Order No. 679 for other plant investments. The total ROE for any project, including any authorized ROE incentives for Post-2003 PTF Investment and any other incentive ROE approved by FERC under Order No. 679 shall be capped by the top of the applicable zone of reasonableness determined by FERC for the relevant period. The data used in determining Eversource's Localized Incremental Return and Associated Taxes for Localized Post-2003 Investment shall be based on actual data in lieu of allocated data if specifically identified in Eversource accounting records.

I. Definitions

Capitalized terms not otherwise defined in the Tariff and as used in this formula have the following definitions:

A. Allocation Factors

1. Localized Transmission Allocation Factor shall equal the ratio of Localized Transmission Plant in Service to total investment in Transmission Plant.

2. Total Localized Plant Allocation Factor shall equal the ratio of Localized Transmission Plant in Service to Total Plant in Service.

3. Transmission Wages and Salaries Allocation Factor shall equal the ratio of Eversource's Transmission-related direct wages and salaries, including those of affiliated companies, to Eversource's total direct wages and salaries, including those of affiliated companies, and excluding administrative and general wages and salaries.

B. Terms

Administrative and General Expense shall equal Eversource's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928 and 930.1 and excluding Merger-Related Costs included in FERC Account Nos. 920-935 (other than those in FERC Account Nos. 924, 928 and 930.1, which have already been excluded).

Amortization of Loss on Reacquired Debt shall equal Eversource's expenses as recorded in FERC Account No. 428.1.

Amortization of Investment Tax Credits shall equal Eversource's expenses as recorded in FERC Account No. 411.4.

Depreciation Expense for Localized Transmission Plant shall equal Eversource's Localized Facilities expenses as recorded in FERC Account No. 403.

Dispatch Center means CL&P's CONVEX dispatch center.

Dispatch Center Plant shall equal CL&P's gross plant balance for the Dispatch Center as recorded in FERC Account Nos. 350-359 and 389-399.

General Plant shall equal Eversource's gross plant balance as recorded in FERC Account Nos. 389-399 less Dispatch Center general plant.

General Plant Depreciation Expense shall equal Eversource's general plant expenses as recorded in FERC Account No. 403 less the portion of such expense for the Dispatch Center.

General Plant Depreciation Reserve shall equal Eversource's general plant reserve balance as recorded in FERC Account No. 108 less the portion of such reserve for the Dispatch Center.

Merger-Related Costs shall equal Eversource's amortized merger-related costs as authorized by FERC or by state regulatory order.

Payroll Taxes shall equal those payroll expenses as recorded in Eversource's FERC Account Nos. 408.1 and 409.1.

Prepayments shall equal Eversource's prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal Eversource's expenses as recorded in FERC Account No. 924.

Total Accumulated Deferred Income Taxes shall equal the net of Eversource's deferred tax balance as recorded in FERC Account Nos. 281-283 and Eversource's deferred tax balance as recorded in FERC Account No. 190.

Total Loss on Reacquired Debt shall equal Eversource's expenses as recorded in FERC Account 189.

Total Municipal Tax Expense shall equal Eversource's expenses as recorded in FERC Account Nos. 408.1, 409.1.

Transmission Merger-Related Costs shall equal Eversource's amortized merger-related transmission costs as authorized by FERC.

Localized Transmission Plant in Service shall equal Eversource's Localized Facilities gross plant balance as recorded in FERC Account Nos. 350-359.

Localized Transmission Plant Held for Future Use shall equal Eversource's Localized Facilities balance as recorded in FERC Account 105.

Localized Transmission Depreciation Reserve shall equal Eversource's Localized Facilities reserve balance as recorded in FERC Account 108.

Transmission Operation and Maintenance Expense shall equal Eversource's expenses as recorded in FERC Account Nos. 560, 561.5 – 561.8, 562-564 and 566-576.5 and shall exclude all HQ HVDC expenses booked to accounts 560 through 576.5 and expenses already included in Transmission Support Expense, as described in Section I below, which are included in FERC Account Nos. 560-576.5.

Transmission Plant shall equal Eversource's gross plant balance as recorded in FERC Account Nos. 350-359.

Transmission Plant Materials and Supplies shall equal Eversource's balance as assigned to transmission, as recorded in FERC Account 154.

Total Plant in Service shall equal Eversource's total gross plant balance as recorded in FERC Account Nos. 301-399.

II. Calculation of Localized Transmission Revenue Requirements

The Localized Transmission Revenue Requirements shall equal the sum of Eversource's (A) Localized Return and Associated Income Taxes (including the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment), (B) Localized Transmission Depreciation Expense, (C) Localized Transmission Related Amortization of Loss on Reacquired Debt, (D) Localized Transmission Related Amortization of Investment Tax Credits, (E) Localized Transmission Related Municipal Tax Expense, (F) Localized Transmission Related Payroll Tax Expense, (G) Localized Transmission Operation and

Maintenance Expense, (H) Localized Transmission Related Administrative and General Expense , (I) Localized Transmission Support Expense, and (J) Localized Transmission Related Taxes and Fees Charge. The Localized Incremental Return and Associated Income Taxes for Localized Post-2003 PTF Investment for Eversource shall be calculated using the investment base components specifically identified in Section A.1 of the formula below.

A. Localized Return and Associated Income Taxes shall equal the product of the Localized Transmission Investment Base and the Cost of Capital Rate. To calculate the Localized Incremental Return and Associated Income Taxes for Localized Post-2003 PTF Investment, Localized Transmission Plant will only include Sections II.A.1.(a), (c), and (d), in the manner indicated.

1. Localized Transmission Investment Base

The Localized Transmission Investment Base will be the average balances of (a) Localized Transmission Plant, plus (b) Localized Transmission Plant Held for Future Use less (c) Localized Transmission Related Depreciation Reserve, less (d) Localized Transmission Related Accumulated Deferred Taxes, plus (e) Localized Transmission Related Loss of Reacquired Debt, plus (f) Localized Transmission Prepayments, plus (g) Localized Transmission Materials and Supplies, plus (h) Localized Transmission Related Cash Working Capital.

(a) Localized Transmission Plant will equal the balance of (1) Eversource's investment in Localized Transmission Plant plus, (2) Eversource's balance of investment in General Plant multiplied by the Transmission Wages and Salaries Allocation Factor, further multiplied by the Localized Transmission Allocation Factor. In order to calculate the Localized Incremental Return and Associated Income Taxes for Localized Post-2003 PTF Investment, Localized Post-2003 PTF Transmission Plant shall be separately identified.

(b) Localized Transmission Plant Held for Future Use shall equal Eversource's balance of Localized Transmission Plant Held for Future Use.

(c) Localized Transmission Related Depreciation Reserve shall equal the balance of Localized Transmission Depreciation Reserve plus the balance of Localized Transmission Related General Plant Depreciation Reserve. Localized Transmission Related General Plant Depreciation Reserve shall equal the product of General Plant Depreciation Reserve and the Transmission Wages and Salaries Allocation Factor, further multiplied by the Localized

Transmission Allocation Factor. In order to calculate the Localized Incremental Return and Associated Income Taxes for Localized Post-2003 PTF Investment, Localized Transmission Related Depreciation Reserve associated with Localized Post-2003 PTF Investment shall equal Eversource's balance of Localized Transmission Depreciation Reserve.

(d) Localized Transmission Related Accumulated Deferred Taxes shall equal Eversource's electric balance of Total Accumulated Deferred Income Taxes, multiplied by the Total Localized Plant Allocation Factor. To calculate the Localized Incremental Return and Associated Income Taxes for Localized Post-2003 PTF Investment, Localized Transmission Related Accumulated Deferred Taxes associated with Localized Post-2003 PTF Investment shall equal Eversource's electric balance of Total Accumulated Deferred Income Taxes multiplied by the Total Localized Plant Allocation Factor.

(e) Localized Related Loss on Reacquired Debt shall equal Eversource's electric balance of Total Loss on Reacquired Debt multiplied by the Total Localized Plant Allocation Factor.

(f) Localized Transmission Prepayments shall equal Eversource's electric balance of Prepayments multiplied by the Transmission Wages and Salaries Allocation Factor and further multiplied by the Localized Transmission Allocation Factor.

(g) Localized Transmission Materials and Supplies shall equal Eversource's electric balance of Transmission Plant Materials and Supplies multiplied by the Localized Transmission Allocation Factor.

(h) Localized Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of (i) Localized Transmission Operation and Maintenance Expense, plus (ii) Localized Administrative and General Expense.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) Eversource's Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon the average capital structure and will equal the sum of:

(i) the long term debt component, which equals the product of the actual weighted average embedded cost to maturity of Eversource's long-term debt then outstanding and the ratio that long-term debt is to Eversource's total capital.

(ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of Eversource's preferred stock then outstanding and the ratio that preferred stock is to Eversource's total capital.

(iii) the return on equity component shall equal the product of Eversource's return on equity ("ROE") of 11.07% and the ratio that common equity is to Eversource's total capital. In order to calculate the Localized Incremental Return and Associated Taxes for Post-2003 PTF Investment, the Localized Incremental Return on Equity shall be the product of (1) Eversource's incremental return on equity of 1% for transmission plant investments associated with projects included in the RSP and placed in service by December 31, 2008 or otherwise permitted in Docket Nos. ER04-157 et al., and (2) any ROE incentive adder approved by the FERC under Order No. 679 for other transmission plant investments, provided that the total ROE for any project, including any such ROE incentives, shall be capped by the top of the applicable zone of reasonableness determined by FERC for the relevant period; and (3) the ratio of that common equity to total capital.[1]

(b) Federal Income Tax shall equal

[(A+[(C+B)/D]) x (FT)] divided by (1-FT)

where FT is the Federal Income Tax Rate and A is the sum of the preferred stock component and the return on equity component, as determined in Sections II.A.2.(a)(ii) and (iii) above, B is Localized Transmission Related Amortization of Investment Tax Credits, as determined in Section II.D., below, C is the Equity AFUDC component of Localized Transmission Depreciation Expense, as defined in Section II.B., and D is Localized Transmission Investment Base, as Determined in II.A.1., above.

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1 FERC Form-730 contains a list of transmission projects for which FERC has granted incentives under Order No. 679.

(c) State Income Tax Shall equal:

[(A+[(C+B)/D] + Federal Income Tax) x (ST)] divided by (1-ST)

where ST is the State Income Tax Rate, A is the sum of the preferred stock component and return on equity component determined in Sections II.A.2.(a)(ii) and (iii) above, B is the

Localized Transmission Related Amortization of Investment Tax Credits as determined in Section II.D. below, C is the equity AFUDC component of Localized Transmission Depreciation Expense, as defined in Section II.B., D is the Localized Transmission Investment Base, as determined in II.A.1. above and Federal Income Tax is the rate determined in Section II.A.2.(b) above.

B. Localized Transmission Depreciation Expense shall equal the sum of Depreciation Expense for Localized Transmission Plant, plus an allocation of General Plant Deprecation Expense calculated by multiplying General Plant Depreciation Expense by the Transmission Wages and Salaries Allocation Factor and further multiplied by the Localized Transmission Allocation Factor.

C. Localized Transmission Related Amortization of Loss on Reacquired Debt shall equal Eversource’s electric Amortization of Loss on Reacquired Debt multiplied by the Total Localized Plant Allocation Factor.

D. Localized Transmission Related Amortization of Investment Tax Credits shall equal Eversource’s electric Amortization of Investment Tax Credits multiplied by the Total Localized Plant Allocation Factor.

E. Localized Transmission Related Municipal Tax Expense shall equal Eversource’s Total Municipal Tax Expense multiplied by the Total Localized Plant Allocation Factor.

F. Localized Transmission Related Payroll Tax Expense shall equal Eversource’s electric Payroll Taxes expense, multiplied by the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Localized Transmission Allocation Factor.

G. Localized Transmission Operation and Maintenance Expense shall equal Eversource's Transmission Operation and Maintenance Expense multiplied by the Localized Transmission Allocation Factor.

H. Localized Transmission Related Administrative and General Expense shall equal the sum of (1) Eversource's Administrative and General Expense multiplied by the Transmission Wages and Salaries Allocation Factor and further multiplied by the Localized Transmission Allocation Factor, (2) Property Insurance multiplied by the Total Localized Plant Allocation Factor, (3) Expenses included in Account 928 (excluding Merger-Related Costs included in Account 928) related to FERC Assessments multiplied by the Total Localized Plant Allocation Factor, (4) Federal and State transmission related expenses or assessments in Account 928 multiplied by the Localized Transmission Allocation Factor, (5) specific transmission related expenses included in Account No. 930.1, multiplied by the Localized Transmission Allocation Factor, plus Transmission Merger-Related Costs multiplied by the Localized Transmission Allocation Factor and (6) specific Localized Facility related public education expenses included in Account 426.54.

I. Transmission Support Expense shall equal the expense paid by Eversource for transmission support for Localized Facilities.

J. Transmission Related Taxes and Fees Charge shall include any fee or assessment imposed by any governmental authority on transmission service provided under this Local Service Schedule that is not specifically identified under any other section of this Local Service Schedule, multiplied by the Localized Transmission Allocation Factor.

SCHEDULE 21-ES

ATTACHMENT ES-L

Creditworthiness Procedures

1. **General Information**

All customers taking any service under Schedule 21-ES, the Local Service Schedule ("LSS"), and the associated schedules of The Connecticut Light and Power Company, Western Massachusetts Electric Company, and Public Service Company of New Hampshire ("Eversource") must meet the terms of this Attachment ES-L.

2. **Establishing Creditworthiness**

a) Each customer's creditworthiness must be established before receiving transmission services from Eversource. A customer will be evaluated at the time that its application for transmission service is provided to Eversource based on the creditworthiness information required under this Attachment ES-L. Eversource shall conduct a credit review of each Transmission Customer not less than annually or upon reasonable request by the Transmission Customer.

b) Eversource will review the customer's creditworthiness information for completeness and will notify the customer if additional information is required.

c) Upon completion of a creditworthiness evaluation of a customer, Eversource will forward a written evaluation to the customer if they determine that Financial Assurance must be provided.

3. Financial Information

Customers requesting transmission service must submit if available the following:

a) All current rating agency reports of the customer from Standard and Poor's ("S&P"), Moody's Investors Service ("Moody's"), and/or Fitch Ratings ("Fitch").

b) A Management Discussion and Analysis ("MD&A") along with audited financial statements provided by an independent registered public accounting firm or a registered

independent auditor for the three (3) most recent fiscal years, or the period of the customer's existence, if shorter than three (3) years.

4. Creditworthiness – Qualification for Unsecured Credit

a) A customer may receive unsecured credit from Eversource equivalent to three (3) months of the transmission charges. The customer must meet at least one of the following criteria:

(i) If rated, the customer's lowest rating from the three rating agencies on its senior unsecured long-term debt; or if the customer does not have such a rating, then one rating level below the rating then assigned to the customer's corporate credit rating, as follows:

1. a Standard and Poor's or Fitch rating of at least BBB, or

2. a Moody's rating of least Baa2.

(ii) If un-rated or if rated below BBB/Baa2, as described in 4(a)(i) above, the customer must meet all of the following creditworthiness criteria for the three (3) most recent fiscal years:

1. A Capitalization Ratio (Debt divided by the sum of shareholders' equity and Debt) of no more than 60 percent Debt, where "Debt" is defined as the sum of all long-term and short-term debt, preferred securities and capital leases. Each of which is recorded in accordance with generally accepted accounting principles;

2. Earnings before interest, taxes, depreciation and amortization ("EBITDA") in the most recent fiscal quarter divided by interest expense (ratio of EBITDA-to-interest expense of at least three (3) times); and

3. Audited Financial Statements with an unqualified auditor opinion.

b) If the customer relies on the creditworthiness of a parent company, the parent company must satisfy the ratings criteria in Section 4(a) above, and must provide to Eversource a written

guarantee that it will be unconditionally responsible for all financial obligations associated with the customer's receipt of transmission service from Eversource.

c) If the customer or the customer's parent company do not qualify for unsecured credit under Sections 4(a) or (b) above, the customer can still qualify for unsecured credit equivalent to three (3) months of transmission service charges, if:

(i) the customer has, on a rolling basis, 12 consecutive months of payments to Eversource with no missed, late or defaults in payment; or

(ii) the customer has an executed long-term contract for the sale of the full output (energy and capacity) of its generating unit and either has executed a corresponding service transmission service agreement under Schedule 21-ES for the transmission of that output or the execution of such agreement is pending the customer's demonstration of creditworthiness.

5. Financial Assurance

If the customer does not meet the applicable requirements for unsecured credit set out in Section 4 then the customer must either:

a) pay in advance an amount equal to the lesser of the total charge for transmission service not less than five (5) days in advance of the commencement of service, in which case Eversource will pay to the customer interest on the amounts not yet due to Eversource, computed in accordance with 18 C.F.R. §35.19(a)(2)(iii) of the Commission's Regulations; or

b) obtain Financial Assurance in the form of a letter of credit or a parent guarantee equal to the equivalent of three (3) months of transmission service charges prior to receiving service.

(i) The letter of credit must be one or more irrevocable, transferable standby letters of credit issued by a United States commercial bank or a United States branch of a foreign bank provided that such customer is not an affiliate of such bank. The issuing bank must have a credit rating of at least A2 from Moody's or an A rating from S&P or Fitch, or an equivalent credit rating by another nationally recognized rating service reasonably acceptable to Eversource, provided that such bank shall have assets totaling not less than

ten billion dollars ($10,000,000,000). All costs of the letter of credit shall be borne by the applicant for such letter of credit. In the event of an inconsistency in the ratings by Moody's, S&P, or Fitch, a "split rating", the lowest credit rating shall apply.

(ii) If the credit rating of a bank or other financial institution issuing a letter of credit to a customer falls below the levels specified in Section 5(b)(i) above, the customer shall have three (3) business days to obtain a suitable letter of credit from another bank or other financial institution that meets the specified levels unless Eversource agrees in writing to extend such period.

6. Notifications

Each customer must inform Eversource in writing within three (3) business days of any material change in its or its letter of credit issuer's financial condition, and if the customer qualifies under Section 4(b), that of its parent company. A material change in financial condition may include, without limitation, the following:

a) change in ownership by way of a merger, acquisition, or substantial sale of assets;
b) downgrade by a recognized major financial rating agency;
c) placement on credit watch with negative implications by a major financial rating agency;
d) a bankruptcy filing by the customer or parent;
e) any action requiring the filing of a SEC Form 8-K;
f) declaration of or acknowledgement of insolvency;
g) report of a significant quarterly loss or decline in earnings;
h) resignation of key officer(s); or
i) issuance of a regulatory order and/or the filing of a lawsuit that could materially adversely impact current or future financial results.

7. Ongoing Financial Review

Each customer is required to submit to Eversource annually or when issued, as applicable:

a) current rating agency reports;
b) audited financial statements from an independent registered public accounting firm or a registered independent auditor; and
c) SEC Forms 10-K and 8-K, promptly upon their filing.

8. Change in Creditworthiness Status

A customer who has been extended unsecured credit pursuant to Section 4, must comply with the terms of Financial Assurance in Section 5, if one or more of the following conditions apply:

a) the customer no longer meets the applicable criteria for unsecured credit in Section 4;

b) the customer exceeds the amount of unsecured credit extended by Eversource, in which case Financial Assurance equal to the amount of exceeded unsecured credit must be provided within five (5) business days; or

c) the customer has missed two or more payments for any of the transmission services provided by Eversource in the last twelve (12) months.

9. Procedures for Changes in Credit Levels and Collateral Requirements

a) Eversource shall issue notice to a customer of any changes to the approved credit levels and/or collateral requirements within five (5) business days after (1) receiving notification of any material changes in financial condition under Section 6 above; (2) receiving the information required for the customer's ongoing financial review listed in Section 7 above; or (3) the occurrence of any of the events leading to a change in creditworthiness requirements listed in Section 8 above.

b) A customer may submit a written request that Eversource provide an explanation of the reasons for the changes in credit levels and/or collateral requirements within five (5) business days after receiving notification of the changes. Eversource will provide a written response within five (5) business days after receiving such a request.

10. Contesting Creditworthiness Determinations

A customer may contest Eversource's determination of its creditworthiness by submitting a written request for re-evaluation within 20 calendar days of being notified of the creditworthiness determination. The request should provide information supporting the basis for a re-evaluation of the customer's creditworthiness. Eversource will review the request and respond within 20 calendar days of receipt.

11. Process for Changing Credit Requirements

a) In the event Eversource plans to revise the Schedule 21-ES requirements for credit levels or collateral requirements described in this Attachment ES-L, they will make a filing under Section 205 of the Federal Power Act.

b) Eversource shall provide written notification to ISO-NE and stakeholders of any filing described above, at least 30 days in advance of such filing.

c) Filing notifications shall include a detailed description of the filing, including a redlined document containing revised changes(s) to this Attachment ES-L.

d) Eversource shall consult with interested stakeholders upon request.

e) Following Commission acceptance of such filing and upon the effective date, Eversource shall revise its Attachment ES-L an updated version of Schedule 21-ES shall be posed to the ISO-NE web site.

f) When Eversource changes its credit requirements for service under Schedule 21-ES, the customer is responsible for forwarding updated financial information to Eversource. The customer must indicate whether the change affects its ability to meet the requirements of Attachment ES-L. In cases where the customer’s credit status has changed, the customer must take the necessary steps to comply with the revised credit requirements of Attachment ES-L by the effective date of the change.

12. Suspension of Service

Eversource may immediately suspend service (with notification to the Commission) to a customer, and may initiate proceedings with the Commission to terminate service, if the customer does not meet the terms described in Sections 4 through 8 at any time during the term of service or if the customer’s payment obligations to Eversource exceed the amount of unsecured or secured credit to which it is entitled under this Attachment ES-L. A customer is not obligated to pay for transmission service that is not provided as a result of a suspension of service.

ATTACHMENT F

ANNUAL TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirements for each PTO will reflect the PTO's costs with respect to Pool Supported PTF and the HTF, including costs attributable to those PTOs deemed to own or support PTF pursuant to Section II.49 of the Tariff. The Transmission Revenue Requirements will be an annual calculation based on the previous year's calendar data as shown, in the case of PTOs that are subject to the Commission's jurisdiction, in the PTO's FERC Form 1 report for that year; provided, however, that if a PTO is deemed to own or support PTF pursuant to Section II.49 of the Tariff, such PTO may include the costs as incurred by its Related Person for PTF facilities and Transmission Support Expenses as the basis for establishing its initial and subsequent Annual Transmission Revenue Requirements, only until such PTO has a full calendar year of cost data under its ownership. Such PTO's costs will be determined from FERC Form 1 data if available, or if not available, from other supporting data certified by an auditor of the PTO or Related Person, and in a format comparable to that used to report such costs in FERC Form 1. Such costs shall be based on actual data in lieu of allocated data if specifically identified in the Form 1 report in accordance with the following formula and Schedule 12:

I. The Transmission Revenue Requirement shall equal the sum of the PTO's (A) Return and Associated Income Taxes, (B) Transmission Depreciation and Amortization Expense, (C) Transmission Related Amortization of Loss on Reacquired Debt, (D) Transmission Related Amortization of Investment Tax Credits, (E) Transmission Related Municipal Tax Expense, (F) Transmission Related Payroll Tax Expense, (G) Transmission Operation and Maintenance Expense, (H) Transmission Related Administrative and General Expense, (I) Transmission Related Integrated Facilities Charges, minus (J) Transmission Support Revenue, plus (K) Transmission Support Expense, plus (L) Transmission Related Expense from Generators, plus (M) Transmission Related Taxes and Fees Charge, minus (N) Revenue for Short-Term service under the OATT and (O) Transmission Rents Received from Electric Property.

The details for implementation of Attachment F, as well as the definitions of the terms used in the Attachment F formula, shall be established in accordance with the Attachment F Implementation Rule contained in this OATT.

ATTACHMENT F

IMPLEMENTATION RULE

This rule sets forth details with respect to the determination each year of the Transmission Revenue Requirements for each PTO. Such Transmission Revenue Requirements shall reflect the PTO’s costs for Pool Transmission Facilities (“PTF”) and the Highgate Transmission Facilities (“HTF”), including costs attributable to those PTOs deemed to own or support PTF pursuant to Section II.49 of the Tariff. The Transmission Revenue Requirements for each PTO will reflect the PTO’s costs with respect to Pool Supported PTF and the HTF. The Transmission Revenue Requirements will be an annual calculation based on the previous year’s calendar data as shown, in the case of PTOs which are subject to the Commission’s jurisdiction, in the PTO’s FERC Form 1 report for that year; provided, however, that if a PTO is deemed to own or support PTF, such PTO may include the costs as incurred by its Related Person for PTF facilities and Transmission Support Expenses as the basis for establishing its initial and subsequent Annual Transmission Revenue Requirements, only until such PTO has a full calendar year of cost data under its ownership. Such PTO’s costs will be determined from FERC Form 1 data if available, or if not available, from other supporting data certified by an auditor of the PTO or Related Person, and in a format comparable to that used to report such costs in FERC Form 1. Such costs shall be based on actual data in lieu of allocated data if specifically identified in the Form 1 report in accordance with the following formula and Schedule 12. The HTF Transmission Revenue Requirements shall be subject to the limitations of inclusion of such costs as set forth in Appendix B to this Attachment. The owners of the HTF, or their designated agent, will submit the annual HTF Transmission Revenue Requirements calculation based on the previous calendar year's cost data from their FERC Form 1 or equivalent information from their official books and records, as appropriate.

The Post-96 Transmission Revenue Requirement for each PTO that is based on data for calendar year 2004 or later shall include an Incremental Return and Associated Income Taxes on the PTO's PTF transmission plant investments included in the Regional System Plan and placed in-service on or after January 1,2004 (such investments referred to herein as "Post-2003 PTF Investment"). The Incremental Return and Associated Income Taxes for Post-2003 PTF Investment shall incorporate an incentive ROE adder of 100 basis points for plant investment placed in service by December 31, 2008 or as otherwise permitted in Docket Nos. ER04-157, et al. for any projects included in the RSP, and shall incorporate any incentive ROE adder approved by the FERC under Order No. 679 for other plant investments and for MPRP CWIP and NEEWS CWIP. The total ROE for any project, including any authorized ROE incentives for Post-2003 PTF Investment and any other incentive ROE approved by FERC under Order

No. 679 shall be capped by the top of the applicable zone of reasonableness determined by FERC for the relevant period. The data used in determining each PTO's Incremental Return and Associated Taxes for Post-2003 Investment shall be based on actual data in lieu of allocated data if specifically identified in the PTO's accounting records.

The Post-1996 Pool PTF Rate, as calculated pursuant to Schedule 9, shall include for each PTO a Forecasted Transmission Revenue Requirement calculated in accordance with Appendix C to this Attachment F Implementation Rule. Additionally, the Pre-1997 and Post-1996 Pool PTF Rates shall include an Annual True-up calculated in accordance with Appendix C to this Attachment F Implementation Rule.

The PTOs shall make an annual informational filing on or before July 31 of each year showing the Pool PTF Rate in effect for the period beginning June 1 of that year through May 31 of the subsequent year.Further, the informational filing with respect to the determination of the Pool PTF Rate will include a breakdown by PTO of the amount of the change in PTF and HTF investment during the prior year and the PTF and HTF retirements or additions causing such change to beginning and end-of-year PTF balances and HTF balances (although beginning-of-year PTF balances and HTF balances are not used in the formula itself), and any additions to PTF and HTF, retirements of PTF and HTF, and reclassifications of PTF and HTF during the year for each PTO. If there are any corrections made to the information reflected in the informational filing after it has been submitted, the PTOs will file corrections to the informational filing. At least forty-five days before the informational filing is made with the Commission, the PTOs shall make available to Transmission Customers and any other interested parties a draft of the proposed filing for review and comment prior to the filing by posting such draft on the ISO website. The filing of the information filing does not re-open the formula rate set forth below for review, but rather is contestable only with respect to the accuracy of the information contained in the informational filing.

The ISO shall have the discretion to conduct audits of such charges, with advisory Stakeholder input on the scope of audit, including on any agreed-upon procedures to be used by the auditor. In this provision, the term “agreed-upon procedures” shall have the meaning afforded to it by the American Institute of Certified Public Accountants.

I. DEFINITIONS

Capitalized terms not otherwise defined in the Tariff and as used in this rule have the following definitions:

A. ALLOCATION FACTORS

1. Transmission Wages and Salaries Allocation Factor shall equal the ratio of Transmission-related direct wages and salaries including those of affiliated Companies to the PTO's total direct wages and salaries including those of the Affiliates' Companies and excluding administrative and general wages and salaries.

2. PTF/HTF Transmission Plant Allocation Factor shall equal the ratio of PTF/HTF Transmission Plant to Total Investment in Transmission Plant, excluding capital leases in the Phase I/II HVDC-TF (Phase I/II HVDC-TF Leases).

3. Plant Allocation Factor shall equal the ratio of the sum of Total Investment in Transmission Plant, excluding Phase I/II HVDC-TF Leases, and Transmission Related Intangible and General Plant to Total Plant in service excluding Phase I/II HVDC-TF Leases.

B. TERMS

Administrative and General Expense shall equal the PTO's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928 and 930.1 and excluding Merger-Related Costs included in FERC Account Nos. 920-935 (other than those in FERC Account Nos. 924, 928 and 930.1, which have already been excluded).

Amortization of Loss on Reacquired Debt shall equal the PTO's expenses as recorded in FERC Account No. 428.1.

Amortization of Investment Tax Credits shall equal the PTO's credits as recorded in FERC Account No. 411.4.

Depreciation Expense for Transmission Plant shall equal the PTO's transmission expenses as recorded in FERC Account No. 403.

General Plant shall equal the PTO's gross plant balance as recorded in FERC Account Nos. 389-399.

General Plant Depreciation and Amortization Expense shall equal the PTO's general expenses as recorded in FERC Account No. 403 and NSTAR Electric's FERC Account No. 404 for items subject to amortization.

General Plant Amortization Reserve shall equal NSTAR Electric's general reserve balance as recorded in FERC Account No. 111.

HTF Transmission Plant shall equal the PTO's balance of investment in the Highgate Transmission Facilities as recorded in FERC Account Nos. 350-359.

Intangible Plant shall equal NSTAR Electric's gross plant balance as recorded in FERC Account No. 303. The only allowable Intangible Plant for inclusion are software, patent or rights costs.

Intangible Plant Amortization Expense shall equal NSTAR Electric's amortization expenses as recorded in FERC Account Nos. 404-405. The only allowable Intangible Plant Amortization Expense for inclusion is the amortization of software, patent or rights costs.

Intangible Plant Amortization Reserve shall equal NSTAR Electric's amortization reserve balance as recorded in FERC Account No. 111. The only allowable Intangible Plant Amortization Reserve for inclusion is that related to the amortization of software, patent or rights costs.

Maine Power Reliability Program Construction Work In Progress ("MPRP CWIP") shall equal Central Maine Power Company's ("CMP's") MPRP CWIP balance as recorded in FERC Account No. 107 for costs determined to be Pool- Supported PTF in accordance with Schedule 12 of this OATT.

Merger-Related Costs shall equal NSTAR Electric Company's ("NSTAR Electric"), CL&P's, Public Service Company of New Hampshire's ("PSNH") and WMECO's amortized merger-related costs as authorized by FERC or by state regulatory order.

New England East-West Solution Construction Work in Progress (“NEEWS CWIP”) shall equal the NEEWS CWIP balances of The Connecticut Light and Power Company (“CL&P”) and Western Massachusetts Electric Company (“WMECO”) and New England Power Company (“NEP”) as recorded in FERC Account No. 107 for costs determined to be Pool-Supported PTF in accordance with Schedule 12 of this OATT.

Other Regulatory Assets/Liabilities - FAS 106 shall equal the net of the PTO's FAS 106 balance as recorded in FERC Account 182.3 and any FAS 106 balance as recorded in the PTO's FERC Account No. 254.

Other Regulatory Assets/Liabilities - FAS 109 shall equal the net of the PTO's FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in the PTO's FERC Account No. 254.

Other Regulatory Assets/Liabilities - shall equal NSTAR Electric’s, CL&P’s, PSNH’s and WMECO’s unamortized balance of merger-related transmission costs recorded in FERC Account No. 182.3 as authorized by FERC.

Payroll Taxes shall equal those payroll expenses as recorded in the PTO's FERC Account Nos. 408.1.

Phase I/II HVDC-TF Leases shall equal the PTO's balance in capital leases as recorded in FERC Account Nos. 350-359 and FERC Account Nos. 389-399.

Plant Held for Future Use shall equal the PTO's balance in FERC Account No.105.

Prepayments shall equal the PTO’s prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal the PTO’s expenses as recorded in FERC Account No. 924.

PTF Transmission Plant shall equal the PTO’s transmission plant as defined in the Section II.49 of the OATT and determined in accordance with Appendix A of this Rule, which is entitled “Rules for Determining Investment To be Included in PTF.”

<u>PTF/HTF Transmission Plant Investment</u> shall equal the PTO's (a) PTF Transmission Plant plus (b) HTF Transmission Plant.

<u>Total Accumulated Deferred Income Taxes</u> shall equal the net of the PTO's deferred tax balance as recorded in FERC Account Nos. 281-283 and the PTO's deferred tax balance as recorded in FERC Account No. 190.

<u>Total Loss on Reacquired Debt</u> shall equal the PTO's expenses as recorded in FERC Account 189.

<u>Total Municipal Tax Expense</u> shall equal the PTO's municipal tax expenses as recorded in FERC Account Nos. 408.1.

<u>Total Plant in Service</u> shall equal the PTO's total gross plant balance as recorded in FERC Account Nos. 301-399.

<u>Total Transmission Depreciation Reserve</u> shall equal the PTO's transmission reserve balance as recorded in FERC Account 108.

<u>Transmission Merger-Related Costs</u> shall equal NSTAR Electric's, CL&P's, PSNH's and WMECO's amortized merger-related transmission costs as authorized by FERC.

<u>Transmission Operation and Maintenance Expense</u> shall equal the PTO's expenses as recorded in FERC Account Nos. 560, 561.5-561.8, 562-564 and 566-573, and shall exclude all Phase I/II HVDC-TF expenses booked to accounts 560 through 573 and expenses already included in Transmission Support Expense, as described in Section K which are included in FERC Account Nos. 560-573.

<u>Transmission Plant</u> shall equal the PTO's Gross Plant balance as recorded in FERC Account Nos. 350-359.

<u>Transmission Plant Materials and Supplies</u> shall equal the PTO's balance as assigned to transmission, as recorded in FERC Account No. 154.

II. CALCULATION OF TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirement shall equal the sum of the PTO's (A) Return and Associated Income Taxes (including the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP), (B) Transmission Depreciation and Amortization Expense, (C) Transmission Related Amortization of Loss on Reacquired Debt, (D) Transmission Related Amortization of Investment Tax Credits, (E) Transmission Related Municipal Tax Expense, (F) Transmission Related Payroll Tax Expense, (G) Transmission Operation and Maintenance Expense, (H) Transmission Related Administrative and General Expenses, (I) Transmission Related Integrated Facilities Charges, minus (J) Transmission Support Revenue, plus (K) Transmission Support Expense, plus (L) Transmission-Related Expense from Generators, plus (M) Transmission Related Taxes and Fees Charge, minus (N) Revenue for Short-Term service under the OATT, (O) Transmission Rents Received from Electric Property and (P) Transmission Revenues from MEPCO Grandfathered Transmission Service Agreements. The Incremental Return and Associated Income Taxes for Post-2003 PTF Investment for each PTO shall be calculated using the investment base components specifically identified in Section A. 1 of the formula below.

A. <u>Return and Associated Income Taxes</u> shall equal the product of the Transmission Investment Base and the Cost of Capital Rate. To calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP, Transmission Investment Base will only include Sections II.A. 1 .(a), (d), (e), (k), and (1) in the manner indicated.

1. <u>Transmission Investment Base</u>

The Transmission Investment Base will be the year end balances of(a) PTF/HTF Transmission Plant, plus (b) Transmission Related Intangible and General Plant, plus (c) Transmission Plant Held for Future Use, less (d) Transmission Related Depreciation and Amortization Reserve, less (e) Transmission Related Accumulated Deferred Taxes, plus (f) Transmission Related Loss on Re.acquired Debt, plus (g) Other Regulatory Assets/Liabilities, plus (h) Transmission Prepayments, plus (i) Transmission Materials and Supplies, plus (j) Transmission Related Cash Working Capital, plus (k) MPRP CWIP, plus (l) NEEWS CWIP.

(a) <u>PTF Transmission Plant</u> will equal the balance of the PTO's PTF Investment in (a) Transmission Plant plus (b) HTF Transmission Plant. This value excludes (i) the PTO's

Phase I/II HVDC-TF Leases, (ii) the portion of any facilities, the cost of which is directly assigned under Schedule 11 to the OATT, to the Transmission Customer or a Generator Owner or Interconnection Requester, (iii) the Pre-1997 PTF gross plant investment associated with leased facilities occupied by the Phase II section of the Phase I/II HVDC-TF. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment, Post2003 PTF Transmission Plant shall be separately identified.

(b) Transmission Related Intangible and General Plant shall equal the sum of the PTO's balance of investment in Intangible Plant and General Plant multiplied by the Transmission Wages and Salaries Allocation Factor and the PTF/HTF Transmission Plant Allocation Factor.

(c) Transmission Plant Held for Future Use shall equal the PTO's balance of Transmission-related Plant Held for Future Use multiplied by the PTF/HTF Transmission Plant Allocation Factor.

(d) Transmission Related Depreciation and Amortization Reserve shall equal the PTO's balance of Total Transmission Depreciation Reserve, plus the balance of Transmission Related Intangible Plant Amortization Reserve, Transmission Related General Plant Depreciation Reserve and Transmission Related General Plant Amortization Reserve. Transmission Related Intangible Plant Amortization Reserve, Transmission Related General Plant Depreciation Reserve and Transmission Related General Plant Amortization Reserve shall equal the product of the sum of Intangible Plant Amortization Reserve, General Plant Depreciation Reserve and General Plant Amortization Reserve, and the Transmission Wages and Salaries Allocation Factor. This sum shall be multiplied by the PTF/HTF Transmission Plant Allocation Factor. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment, Transmission Depreciation Reserve associated with Post-2003 PTF Investment shall equal the PTO's balance of Total Transmission Depreciation Reserve multiplied by the ratio of Post-2003 PTF Transmission Plant to Total Investment in Transmission Plant, excluding capital leases in the Phase I/II HVDC-TF Leases.

(e) Transmission Related Accumulated Deferred Taxes shall equal the PTO's electric balance of Total Accumulated Deferred Income Taxes, multiplied by the Plant Allocation

Factor, further multiplied by the PTF/HTF Transmission Plant Allocation Factor. To calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment, Transmission Related Accumulated Deferred Income Taxes associated with Post-2003 PTF Investment shall equal the PTO's balance of total property-related accumulated deferred income taxes as recorded in FERC accounts 281 and 282, multiplied by the ratio of Total Investment in Transmission Plant, excluding Phase I/II HVDC-TF Leases, to Total Plant in Service excluding Phase I/II HVDC-TF Leases, further multiplied by the ratio of Post-2003 PTF Transmission Plant to Total Investment in Transmission Plant, excluding Phase I/II HVDC-TF Leases.

(f) Transmission Related Loss on Reacquired Debt shall equal the PTO's electric balance of Total Loss on Reacquired Debt multiplied by the Plant Allocation Factor, further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

(g) Other Regulatory Assets/Liabilities shall equal the PTO's electric balance of any deferred rate recovery of FAS 106 expenses multiplied by the Transmission Wages and Salaries Allocation Factor, plus the PTO's electric balance of FAS 109 multiplied by the Plant Allocation Factor, plus NSTAR Electric's, CL&P's, PSNH's and WMECO's unamortized balance of merger-related transmission costs recorded in FERC Account No. 182.3 as authorized by FERC. This sum shall be multiplied by the PTF/HTF Transmission Plant Allocation Factor.

(h) Transmission Prepayments shall equal the PTO's electric balance of prepayments multiplied by the Transmission Wages and Salaries Allocation Factor and further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

(i) Transmission Materials and Supplies shall equal the PTO's electric balance of Transmission Plant Materials and Supplies, multiplied by the PTF/HTF Transmission Plant Allocation Factor.

(j) Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of the PTO's Transmission Operation and Maintenance Expense, Transmission Related Administrative and General Expense and Transmission Support Expense, to the extent that Transmission Support Expense exceeds Transmission Support Revenue included in Paragraph J of the formula.

(k) MPRP CWIP shall equal CMP's balance as recorded in FERC Account No. 107 for the MPRP as authorized by Commission order and in accordance with CMP's Accounting Procedures for MPRP CWIP. In order to calculate the Incremental Return and Associated Income Taxes for MPRP CWIP, MPRP CWIP shall be separately identified.

(l) NEEWS CWIP shall equal CL&P, WMECO and NEP’s balances as recorded in FERC Account No. 107 for the NEEWS as authorized by Commission order and in accordance with the companies’ respective Accounting Procedures for NEEWS CWIP. In order to calculate the Incremental Return and Associated Income Taxes for NEEWS CWIP, NEEWS CWIP shall be separately identified.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) the PTO's Weighted Cost of Capital, plus (b) Federal Income Tax plus (e) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon the capital structure at the end of each year and will equal the sum of (i), (ii), and (iii) below. The Cost of Capital Rate to be used in calculating the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP, shall only reflect item (iii) below and shall apply in the manner indicated below.

(i) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity of the PTO's long-term debt then outstanding and the ratio that long-term debt is to the PTO's total capital.

(ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of the PTO's preferred stock then outstanding and the ratio that preferred stock is to the PTO's total capital.

(iii) the return on equity component, shall be the product of the allowed ROE of the PTO's common equity and the ratio that common equity is to the PTO's total capital. For pre-

1997 and post-1996 assets, the ROE is 11.07%. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP, the incremental return on equity shall be the product of: (1) the PTO's incremental return on equity of 1.0% for plant investments associated with projects included in the RSP and placed in service by December 31, 2008 or otherwise permitted in Docket Nos. ER04-157, et al.; (2) any ROE incentive approved by the FERC under Order No. 679 for other plant investments and MPRP CWIP and NEEWS CWIP, provided that the total ROE for any project, including any such ROE incentives, shall be capped by the top of the applicable zone of reasonableness determined by FERC for the relevant period, and (3) the ratio that common equity is to the PTO's total capital) [1]

(b) Federal Income Tax shall equal

$$\frac{(A+[(C+B)/D])(FT)}{\text{I-FT}}$$

where FT is the Federal Income Tax Rate and A is the sum of the preferred stock component and the return on equity component, as determined in Sections ll.A.2.(a)(ii) and (iii) above, B is Transmission Related Amortization of Investment Tax Credits, as determined in Section II.D., below, C is the Equity AFUDC component of Transmission Depreciation Expense, as defined in Section ll.B., and D is Transmission Investment Base, as determined in Section II.A.1., above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP, the incremental Federal Income Tax shall equal

$$\frac{(A' * FT)}{(1 - FT)}$$

where FT is the Federal Income Tax Rate and A' is the incremental return on equity component, as determined in Section II.A.2.(a)(iii) above.

(c) State Income Tax shall equal

[1] FERC Form-730 contains a list of transmission projects for which FERC has granted incentives under Order No. 679.

$$\frac{(A+[(C+B)/D] + \text{Federal Income Tax})(ST)}{1 - ST}$$

where ST is the State Income Tax Rate, A is the sum of the preferred stock component and return on equity component determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section ll.D.below, C is the equity AFUDC component of Transmission Depreciation Expense, as defined in Section II.B.. D is the Transmission Investment Base, as determined in II.A.1., above and Federal Income Tax is the rate determined in Section II.A.2.(b) above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP, the incremental State Income Tax shall equal

$$\frac{(A' + \text{Federal Income Tax})(ST)}{(1 - ST)}$$

where ST is the State Income Tax Rate, A' is the incremental return on equity component determined in Section II.A.2.(a)(iii) above, and Federal Income Tax is the rate determined in Section II.A.2.(b) above.

B. Transmission Depreciation and Amortization Expense shall equal the PTF/HTF Transmission Plant Allocation Factor, multiplied by the sum of (i) the PTO's Depreciation Expense for Transmission Plant, plus (ii) an allocation of Intangible Plant Amortization Expense and (iii) General Plant Depreciation and Amortization Expense calculated by multiplying the sum of (a) Intangible Plant Amortization Expense and (b) General Plant Depreciation and Amortization Expense by the Transmission Wages and Salaries Allocation Factor.

C. Transmission Related Amortization of Loss on Reacquired Debt shall equal the PTO's electric Amortization of Loss on Reacquired Debt multiplied by the Plant Allocation Factor, and further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

D. Transmission Related Amortization of Investment Tax Credits shall equal the PTO's electric Amortization of Investment Tax Credits multiplied by the Plant Allocation Factor, and further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

E. Transmission Related Municipal Tax Expense shall equal the PTO's total electric municipal tax expense multiplied by the Plant Allocation Factor, and further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

F. Transmission Related Payroll Tax Expense shall equal the PTO's total electric payroll tax expense, multiplied by the Transmission Wages and Salaries Allocation Factor, further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

G. Transmission Operation and Maintenance Expense shall equal the PTO's Transmission Operation and Maintenance Expenses multiplied by the PTF/HTF Transmission Plant Allocation Factor.

H. Transmission Related Administrative and General Expenses shall equal the sum of the PTO's (1) Administrative and General Expenses multiplied by the Transmission Wages and Salaries Allocation Factor, (2) Property Insurance multiplied by the Transmission Plant Allocation Factor, and (3) Expenses included in Account 928 (excluding Merger-Related Costs included in Account 928) related to FERC Assessments multiplied by Plant Allocation Factor, plus any other Federal and State transmission related expenses or assessments, plus specific transmission related expenses included in Account 930.1 plus Transmission Merger-Related Costs. This sum shall be multiplied by the PTF/HTF Transmission Plant Allocation Factor.

I. Transmission Related Integrated Facilities Charges shall equal the PTO's transmission payments to Affiliates for use of the PTF and HTF integrated transmission facilities of those Affiliates.

J. Transmission Support Revenues shall equal the PTO's revenue received for PTF and HTF transmission support but excluding the support payments to PTOs or their designee pursuant to Schedule 11 and excluding the support payments to PTOs or their designee pursuant to Schedule 12 Part 1(a) and Part B.2, and excluding support payments, if any, made to PTOs or their respective designee pursuant to Part II.C of this OATT.

K. Transmission Support Expense shall equal the expense paid by (1) PTOs, (2) Transmission Customers or (3) Related Persons pursuant to Section II.49 of the Tariff for PTF and HTF transmission support other than expenses for payments made for congestion rights or for transmission facilities or facility upgrades placed in service on or after January 1, 1997, where the support obligation is required to be borne by particular PTOs or other entities in accordance with the OATT. Transmission Support Expenses by any entity other than a PTO, included in this provision, shall be capped at that entity's annual payment for Regional Network Service or its Point To Point Service for each individual Point To Point transaction from the resource with which the support payment is associated.

L. <u>Transmission-Related Expense from Generators</u> shall equal the expenses from generators that both (1) the PTO Administrative Committee determines should be included as transmission expense as a result of the impact of such generators on reducing transmission costs that would otherwise be required to be paid by Transmission Customers and (2) are reflected in a filing made by the PTOs with the Commission under Section 205 of the Federal Power Act and accepted by the Commission for recovery under the OATT.

M. <u>Transmission Related Taxes and Fees Charge</u> shall include any fee or assessment imposed by any governmental authority on service provided under this Section which is not specifically identified under any other section of this rule.

N. <u>Revenues for Short-Term service under the OATT</u> shall be revenues distributed to each PTO for short term service provided under the OATT, received after March 1, 1999. These revenues will be credited pro-rata between pre-1997 and post-1996 PTF revenue requirements in proportion to pre-1997 and post-1996 PTF Transmission Plant.

O. <u>Transmission Rents Received from Electric Property</u> shall equal any Account 454 Rents from electric property, associated with PTF and HTF Transmission Plant as defined in Section II.A.1.(a) above but not reflected as a credit in Transmission Support Revenues in paragraph K of this Attachment.

P. <u>Transmission Revenues from MGTSAs</u> shall equal any MGTSA revenues recorded in Account 456.

APPENDIX A TO ATTACHMENT F
IMPLEMENTATION RULE RULES FOR DETERMINING
INVESTMENT TO BE INCLUDED IN PTF

Section A – Transmission Lines*

Section B – Terminal Facilities*

Section C – Right of Way*

Effective June 1, 1998

*The following provision shall apply to Sections A, B and C below:

Of those transmission facilities that are upgrades, modifications or additions to the New England Transmission System on and after January 1, 2004, only those that: (i) are rated 115kV or above, and (ii) otherwise meet the non-voltage criteria specified in Section II.49 of this OATT shall be classified as PTF. Those transmission facilities that were PTF on December 31, 2003, and any upgrades to such facilities that meet the definition of PTF specified in this OATT, shall remain classified as PTF for all purposes under the Transmission, Markets and Services Tariff.

Section A: Rules for Determining Transmission Line Investment to be Included in PTF
Pool Transmission Facilities (PTF) are the transmission facilities owned by PTO rated 69 kV or above required to allow energy from significant power sources to move freely on the New England transmission network, and include:

1. All transmission lines and associated facilities owned by the PTOs rated 69 kV and above, except:

   a. those which are required to serve local load only, thereby contributing little or no parallel capability to the transmission network,

   b. generator leads, which are defined as the radial transmission from a generator bus to the nearest point on the transmission network,

c. lines that are normally operated open.

d. those that are classified as MTF.

2. Terminal facilities (including substation facilities such as transformers, circuit breakers, and associated equipment) required to interconnect the lines which constitute PTF (see Section B).

3. If a PTO with significant generation in its system (initially 25 MW) is connected to the New England Transmission System and none of the transmission facilities owned by the PTO qualify to be included in PTF as defined in “1” and “2” above, then such PTO’s connection to PTF will constitute PTF if both of the following requirements are met for this connection:

   a. The connection is rated 69 kV or above.

   b. The connection is the principal transmission link between the PTO and the remainder of the ISO PTF network.

The PTF facilities covered by this provision shall consist of a single line from the point of connection on the transmission network to the first bus within the PTO’s system.

4. R/W and land required for the installation of PTF facilities listed in “1”, “2”, or “3” (see Section C).

The following examples indicate the intent of the above definitions:

a. Radial tap lines to local load are excluded.

b. Lines which loop, from two geographically separate points on the transmission network, the supply to the load bus from the transmission network are included.

c. Lines which loop, from two geographically separate points on the transmission network, the connections between a generator bus, and the transmission network are included.

d. Radial connection or connections from a generating station to a single substation or switching station on the transmission network are excluded unless the requirements of paragraph 3 above are met.

e. The cost of a PTF line will include only those costs associated with that line. When other facilities require rebuilding or undergrounding to permit the construction of a PTF facility, the investment costs in the relocated or undergrounded facility will not be included.

f. Where multiple circuit structures support a mixture of PTF and Non-PTF circuits, the total cost of the multiple circuit structures will be allocated between the circuits in accordance with the ratio of costs of comparable individual structures.

The PTOs shall review at least annually the status of transmission lines and related facilities and determine whether such facilities constitute PTF and shall prepare and keep current a schedule or catalog of PTF facilities.

All new facilities being installed should be properly classified at the time the facilities are approved under Section I.3.9 of the Transmission, Markets and Services Tariff.

Transmission facilities owned or supported by a Related Person of a PTO which are rated 69 kV or above and are required to allow Energy from significant power sources to move freely on the New England Transmission System shall also constitute PTF provided (i) such Related Person files with the ISO its consent to such treatment; and (ii) the ISO determines in consultation with the PTO Administrative Committee determines that treatment of the facility as PTF will facilitate accomplishment of the ISO's objectives. If such facilities constitute PTF pursuant to this paragraph, they shall be treated as "owned" or "supported," as applicable, by a PTO for purposes of the OATT and the other provisions of the TOA, including the ability to include the cost associated with such PTF and any Transmission Support Expenses for support of PTF made by its Related Person in that PTO's Annual Transmission Revenue Requirements pursuant to Attachment F of the OATT.

Section B: Rules for Determining Terminal Investment to be Included in PTF

Terminal Investment is investment associated with the terminal facilities of electrical lines, including substation facilities such as transformers, circuit breakers, disconnects and airbreaks, bus conductor, related protection equipment and other related facilities (see paragraph 7).

1. The investment in terminal facilities shall be included where these facilities are identifiable and serve directly for terminating and/or switching PTF lines.

2. In cases where a line terminal is used in conjunction with both PTF and Non-PTF lines and/or facilities, it will be considered a PTF facility providing the terminal facility is at 69 kV or above and carries any power flow at 69 kV or above through parallel paths within the interconnected network under normal operation. PTF equipment is any element of the transmission system in those parallel paths. Any equipment not in these parallel paths is Non-PTF.

3. Where line terminals are installed solely for Non-PTF facilities, and do not carry any power flow at 69 kV or above through parallel paths within the interconnected network under normal operation, such terminal cost shall not be included in PTF.

4. A two-winding transformer which connects PTF facilities at both terminals along with any switcher which can be identified as pertaining solely to the transformer, will be included in their entirety as PTF.

5. An autotransformer or three winding transformer which connects PTF facilities at two (2) or more terminals, along with any switchgear which can be identified as pertaining solely to the PTF-connected terminals of the transformer, will be included in their entirety as PTF. An autotransformer or three winding transformer which is connected to PTF at only one terminal will not be PTF.

6. When a transformer supplies only Non-PTF facilities, the entire transformer installation, including the high side disconnect switch or circuit breaker and associated structures or tap lines shall be excluded from PTF except for the portion of line terminal facilities covered by paragraph 2.

7. Other facilities – the investment in that portion of a multi-use substation or switching station which is identifiable as serving a PTF function shall be included in PTF, while the investment in

such facilities which are identifiable as serving a Non-PTF function shall be excluded. The investment in land, structures, ground mats, fences, ducts, lighting, etc., can often be identified and thus allocated. The investment in other facilities in the substation or switching station, excluding transformers, which are not identifiable as serving either a PTF or a Non-PTF function and general overheads shall be allocated to PTF on the basis of the ratio of the investment in those facilities identified as PTF to the sum of the investments in the facilities which are identified as serving PTF and Non-PTF functions; the equipment cost of power transformers shall not be included in this calculation for determining the division of investment, since this would produce a distorted balance.

8. Alternate method of allocating the cost of terminal facilities – In those cases where the major portion of the investment has been lumped and utility plant records do not permit the accurate assignment of costs to specific terminals, the total investment may be prorated to PTF and Non-PTF according to the number of terminals serving PTF and Non-PTF facilities.

9. In cases where microwave facilities are used in whole or part for PTF purposes, a prorated portion of such investment shall be included in PTF based on the PTF and Non-PTF functions served by the microwave facilities except where these facilities are otherwise supported under the Microwave Sharing Agreement dated June 1, 1970 among some of the New England utilities.

10. Generator unit transformers and generator circuit breakers shall be excluded from PTF, unless otherwise included by paragraphs 1 or 5.

11. In cases where remote control (Supervisory Control) and telemetering facilities are used in whole or in part for PTF purposes, a prorated portion of such investment shall be included in PTF based on the PTF and Non-PTF functions served by these facilities.

12. The PTO Administrative Committee may designate appropriate facilities as PTF.

Section C: Rules for Determining PTF R/W Costs

1. If a R/W has only PTF lines and no Non-PTF lines are expected to be added, the entire cost of the R/W is to be included as PTF.

2. If the R/W has only PTF lines but includes additional unused R/W which was purchased for future use by Non-PTF lines, the cost of the additional R/W is not to be included as PTF.

3. If the R/W contains both PTF and Non-PTF lines, the R/W cost to be assigned to PTF is to be determined as follows:

   a. Where new or additional R/W is required to permit the construction of PTF line(s) and the added R/W is adequate to contain the new PTF, the cost of the new R/W is to be assigned to the PTF line(s), (even if the PTF line is located on the old R/W).

   b. Where an existing R/W is used (without additional R/W), the amount allocated to PTF will be determined in accordance with paragraph 4.

   c. Where a R/W is widened, but the new facilities, either PTF or Non-PTF, require partial use of the existing R/W, the incremental cost of the new R/W will be assigned to the new facilities. The width of the original R/W will be added to the width of the new R/W and the combined width will be allocated between PTF and Non-PTF as in paragraph 4. The cost of the old R/W and the combined width will be allocated between PTF and Non-PTF as in paragraph 4. The cost of the old R/W will be allocated to the new facilities in proportion to the width of the old R/W assigned to the new facilities. Thus, the R/W for the new facilities will be the additional R/W plus a share of the old R/W.

4. In allocating R/W between PTF and Non-PTF lines, each shall bear a share of the R/W in accordance with the following formulae.

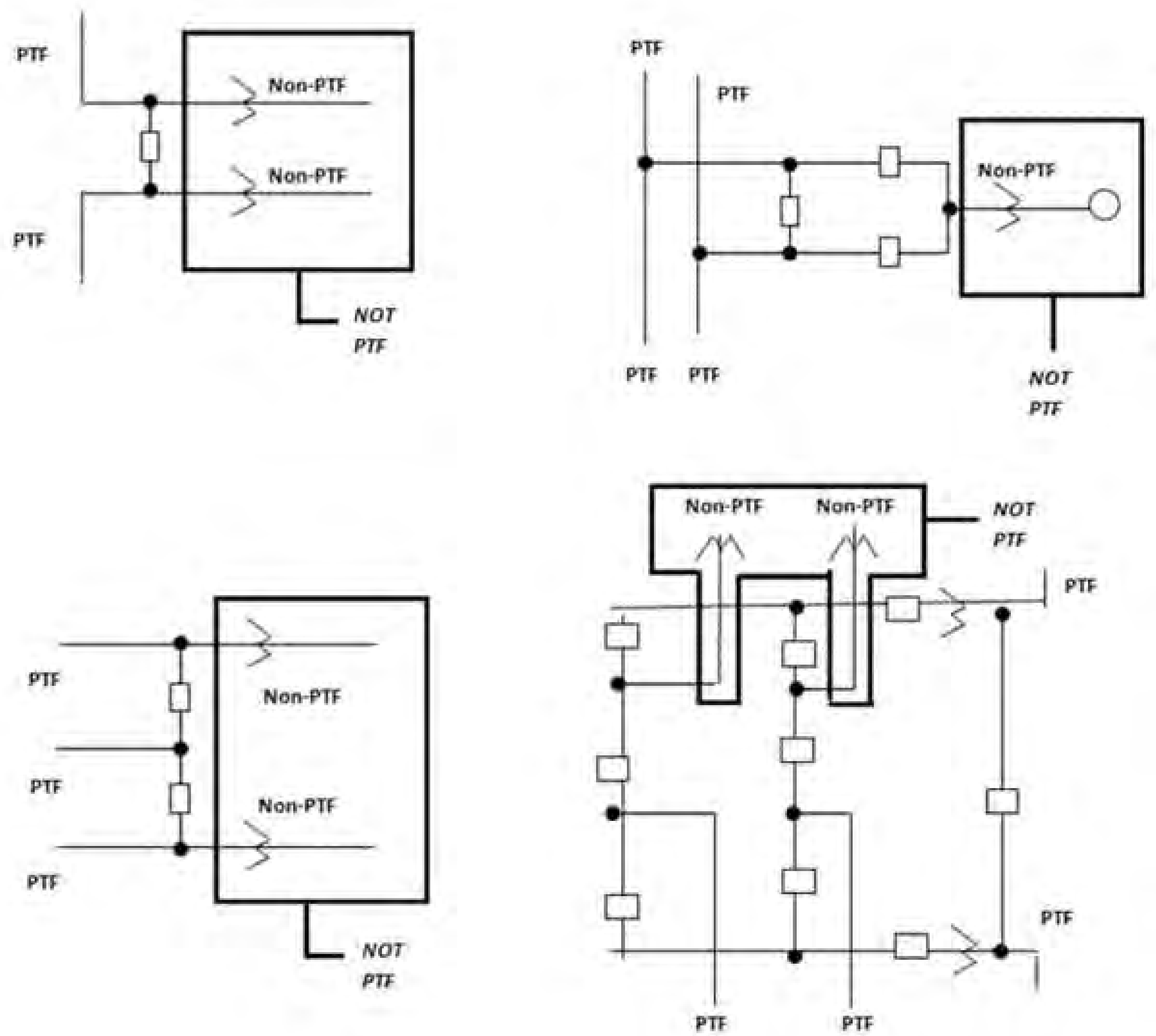
   a. Determine the R/W width required for each facility if constructed independently using appropriate type structures.

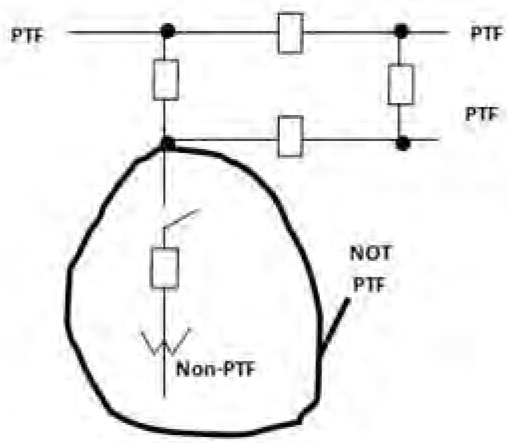
   b. Allocate the actual R/W width to each facility in the proportion its independent R/W requirement would be to the sum of the independent R/W requirements.

5. R/W and land held for future PTF facilities may be included in PTF facilities only if specifically approved by the PTO Administrative Committee included under paragraph 1.

ATTACHMENT 1 TO APPENDIX A TO
ATTACHMENT F IMPLEMENTATION RULE

Examples of the Methods for Distinguishing PTF
from Non-PTF Terminal Facilities
in a Number of Typical Substation Configurations

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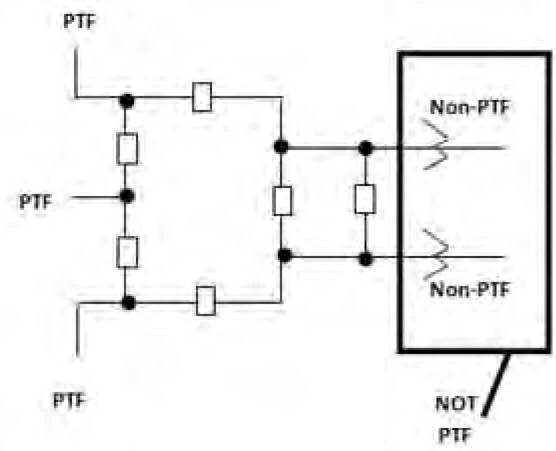
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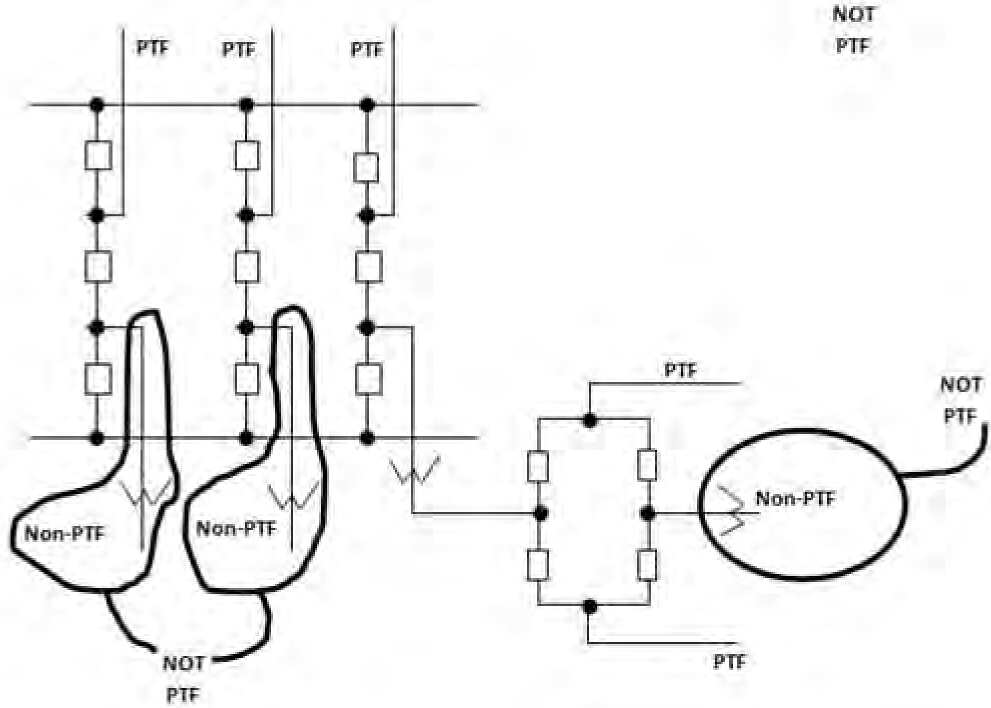
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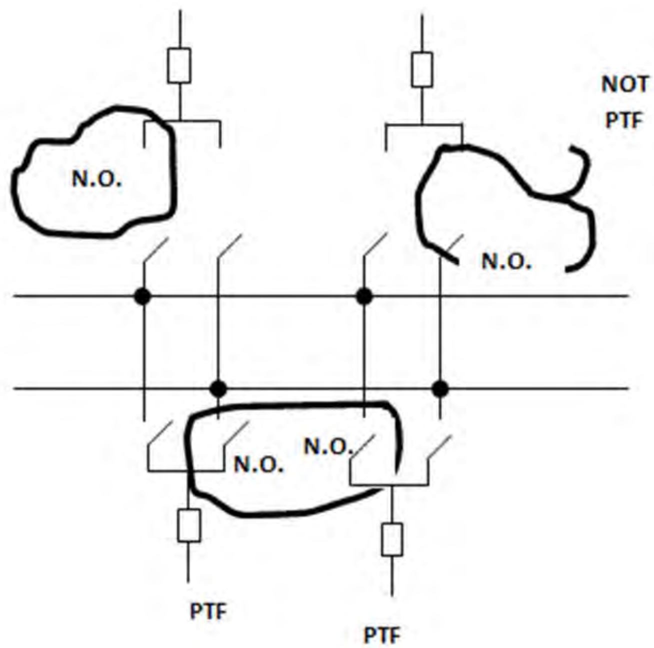
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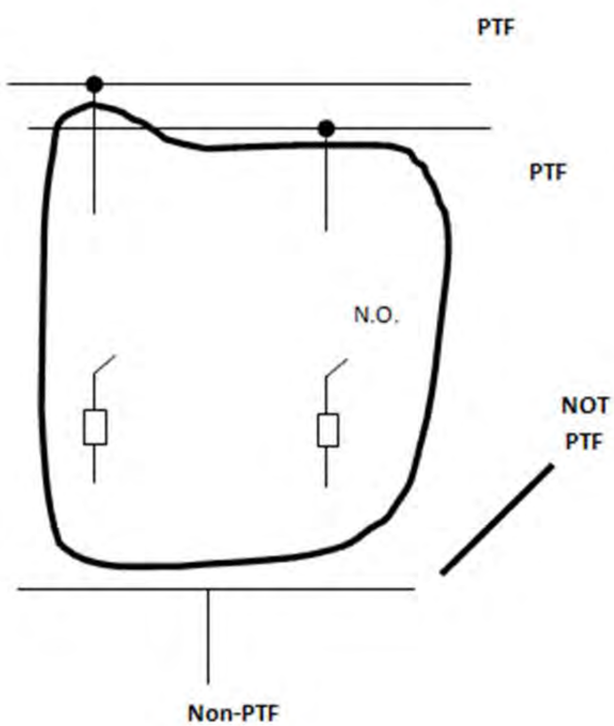
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APPENDIX B TO ATTACHMENT F IMPLEMENTATION RULE

HTF TRANSITION SCHEDULE

The inclusion of HTF Annual Transmission Revenue Requirements in Attachment F (and the calculation of the Pool PTF Rate) to this OATT will be limited by the provisions of this schedule.

VELCO, as a PTO and acting as agent for the HTF owners, may include the HTF Annual Transmission revenue Requirements (i.e., HTF Transmission Plant) within the Attachment F calculations. Additionally, the total HTF Annual Transmission Revenue Requirements included shall be limited to the following:

Year 1: A maximum of $1.2M in Year 1. For the sole purpose of this Schedule, "Year 1" shall be defined as the first full year after the Operations Date:

Year 2: A maximum of $2.0M in Year 2. For the sole purpose of this Schedule, "Year 2" shall be defined as the second full year after the Operations Date;

Year 3: A maximum of $2.8M in Year 3. For the sole purpose of this Schedule, "Year 3" shall be defined as the third full year after the Operations Date;

Year 4: A maximum of $3.5M in Year 4. For the sole purpose of this Schedule, "Year 4" shall be defined as the fourth full year after the Operations Date;

and

Year 5 and thereafter: All HTF Annual Transmission Revenue Requirements shall be included in Attachment F.

ATTACHMENT F IMPLEMENTATION RULE
APPENDIX C

I. DEFINITIONS

(i) **Annual True-up – Pre-1997 (ATU):** shall be the difference between the actual Pre-1997 Annual Transmission Revenue Requirements and the as-billed Pre-1997 Annual Transmission Revenue Requirements, adjusted to include interest pursuant to Part II below. The actual Pre-1997 Annual Transmission Revenue Requirements shall be an after-the-fact calculation and shall be determined at the conclusion of each rate-effective period, i.e. June 1 through May 31 of each year, by application of the Attachment F formula rate and each PTO’s relevant Pre-1997 PTF cost data for the most recently concluded calendar year. The as-billed Pre-1997 Annual Transmission Revenue Requirements shall be those Pre-1997 Annual Transmission Revenue Requirements used to establish the RNS rates that were made effective on June 1 of the most recently concluded calendar year.

(ii) **Annual True-up – Post-1996 (ATU’):** shall be the difference between the actual Post-1996 Annual Transmission Revenue Requirements and the as-billed Post-1996 Annual Transmission Revenue Requirements, adjusted to include interest pursuant to Part II below. The actual Post-1996 Annual Transmission Revenue Requirements shall be an after-the-fact calculation and shall be determined at the conclusion of each rate-effective period, i.e. June 1 through May 31 of each year, by application of the Attachment F formula rate and each PTO's relevant Post-1996 PTF cost data for the most recently concluded calendar year.The as-billed Post-1996 Annual Transmission Revenue Requirements shall be those Post-1996 Annual Transmission Revenue Requirements used to establish the RNS rates that were made effective on June 1 of the most recently concluded calendar year and which included the sum of the Post-1996 Transmission Revenue Requirements for the year prior to the most recently concluded calendar year plus the Forecasted Transmission Revenue Requirements for the most recently concluded calendar year.

(iii) Forecast Period: The calendar year immediately following the calendar year for which the most recent FERC Form 1 data is available.

(iv) Forecasted Transmission Plant Additions (FTPA): shall equal an estimate of the PTO's Post-1996 PTF plant additions for the Forecast Period.

(v) Forecasted MPRP CWIP (FCWIP): shall equal CMP's estimated incremental change in MPRPCWIP for the Forecast Period.

(vi) Carrying Charge Factor (CCF): shall reflect the most recent calendar year data used in determining Post-1996 Annual Transmission Revenue Requirements and shall equal the sum of Attachment F Sections II.A, excluding MPRP CWIP and NEEWS CWIP, through II.H divided by Attachment F Section II.A.1.a.

(vii) MPRP Cost of Capital Rate (MCOC): shall be determined in accordance with Attachment F Section II.A.2.

(viii) Forecasted Transmission Revenue Requirement (FTRR): shall equal FTPA multiplied by the CCF plus FCWIP multiplied by the MCOC, plus FCCWIP multiplied by CCOC, plus FWCWIP multiplied by WCOC, plus FNCWIP multiplied by NCOC, as shown:

FTRR = FTPA * CCF + (FCWIP * MCOC) + (FCCWIP * CCOC) + (FWCWIP * WCOC) + (FNCWIP * NCOC)

(ix) Forecasted CL&P NEEWS CWIP (FCCWIP): shall equal CL&P’s estimated incremental change in NEEWS CWIP for the Forecast Period.

(x) Forecasted WMECO NEEWS CWIP (FWCWIP): shall equal WMECO’s estimated incremental change in NEEWS CWIP for the Forecast Period.

(xi) NEEWS CL&P Cost of Capital Rate (CCOC): shall be determined in accordance with Attachment F Section II.A.2.

(xii) NEEWS WMECO Cost of Capital Rate (WCOC): shall be determined in accordance with Attachment F Section II.A.2.

(xiii) Forecasted NEP NEEWS CWIP (FNCWIP): shall equal NEP’s estimated incremental change in NEEWS CWIP for the Forecast Period.

(xiv) NEEWS NEP Cost of Capital Rate (NCOC): shall be determined in accordance with Attachment F Section II.A.2.

II. INTEREST ON ANNUAL TRUE-UPS

Interest on the Annual True-up amounts (i.e., interest applicable to any over or under collection) shall be calculated in accordance with the methodology specified in the Commission's regulations at 18 C.F.R. § 35.19a (a) (2) (iii).

III. INFORMATIONAL FILINGS

The PTOs' annual informational filing shall include supporting documentation for their estimated capital additions to be placed in service during the current calendar year as well as supporting documentation pertaining to any annual true-up and interest calculations.

SCHEDULE 1

SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE

Scheduling, System Control and Dispatch Service is the service required to schedule at the regional level the movement of power through, out of, within, or into the New England Control Area. Local level service is provided by the PTOs under Schedule 21 to this OATT. For transmission service under this OATT, this Ancillary Service can be provided only by the ISO and the Transmission Customer must purchase this service from the ISO. Charges for Scheduling, System Control and Dispatch Service are to be based on the expenses incurred by the ISO, and by the individual PTOs in the operation of Local Control Center dispatch centers or otherwise, to provide these services. The expenses incurred by the ISO in providing these services recovered under Section IV of the OATT. A surcharge for the expenses incurred by PTOs in the provision of these services for transmission service over the PTF will be added to the Through or Out Service rate and to the Regional Network Service rate. Any Scheduling, System Control and Dispatch Service expenses for the provisions of these services for MTF Service shall be determined separately and assessed to Transmission Customers receiving MTF Service, in accordance with the arrangements between the Transmission Customers receiving MTF Service and the MTF Provider.

The expenses incurred in providing Scheduling, System Control and Dispatch Service for transmission service over the PTF for each PTO will be determined by an annual calculation based on the previous calendar year's data as shown, in the case of PTOs which are subject to the Commission's jurisdiction, in the PTO's FERC Form 1 report for that year, and shall be based on actual data in lieu of allocated data if specifically identified in the Form 1 report. The surcharge shall be redetermined annually as of June 1 in each year and shall be in effect for the succeeding twelve (12) months. The rate surcharge per kilowatt for each month is one-twelfth of the amount derived by dividing the total annual PTO expenses for providing the service by the sum of the average of the coincident Monthly Peaks (as defined in Section II.21.2) of all Local Networks for the prior calendar year.

Each Transmission Customer which is obligated to pay the rate for Regional Network Service for a month shall pay the surcharge on the basis of the number of kilowatts of its Monthly Network Load (as defined in Section II.21.2 of this OATT) for the month. Each Transmission Customer which is obligated to pay the rate for Through or Out Service for the applicable period shall pay the surcharge on the basis of the highest amount of its Reserved Capacity for each transaction scheduled as Through or Out Service for such period.

The details for implementation of Schedule 1 for transmission service over the PTF shall be established in accordance with the Implementation Rule for Schedule 1 attached to this OATT.

SCHEDULE 1 IMPLEMENTATION RULE

This rule provides detail with respect to the calculation of the rate surcharge each year for Scheduling, System Control and Dispatch Service, which is defined in the OATT as the service required to schedule the movement of power through, out of, within, or into the New England Control Area over Pool Transmission Facilities ("PTF"). This service also includes the dispatch and security analysis of the system. Scheduling, System Control and Dispatch Service for transmission service over transmission facilities other than PTF is provided under Schedule 21 of the OATT. For transmission service under the OATT, this Ancillary Service will be provided by the ISO, and rates collected under Schedule 1 are based on expenses incurred by the Local Control Centers, and the PTOs (as described herein) in providing the necessary elements of this service to the ISO. All of the costs of the ISO for the provision of service under Schedule 1 will be recovered under Section IV of the Transmission, Markets and Services Tariff. Schedule 1 of the OATT is for collection only of the revenue requirements for Local Control Centers and PTOs for System Control and Dispatch Service. Any Transmission Customer taking Regional Network Service or Through or Out Service shall be subject to the rate surcharge calculated under Schedule 1 of the OATT as described in more detail in this rule below.

The PTOs shall make an annual informational filing on or before July 31 of each year showing the Schedule 1 rate surcharge to be utilized by the ISO in the billing of Schedule 1 Ancillary Service that will be in effect for the period beginning June 1 of that year through May 31 of the subsequent year. If there are any corrections made to the information reflected in the informational filing after it has been submitted, the PTOs would file corrections to the informational filing. At least thirty (30) days before the informational filing is made with the Commission, the PTOs shall make available to Transmission Customers and any other interested parties a draft of the proposed filing for review and comment prior to the filing by posting such draft on the RTO NE website. The filing of the informational filing does not reopen the formula rate set forth below for review, but rather is contestable only with respect to the accuracy of the information contained in the informational filing. The ISO shall have the discretion to conduct audits of such charges, with advisory Stakeholder input on the scope of audit, including on any agreed-upon procedures to be used by the auditor. In this provision, the term "agreed-upon procedures" shall have the meaning afforded to it by the American Institute of Certified Public Accountants.

I. DEFINITIONS

Capitalized terms used in this rule that are not defined in the Tariff have the following definitions:

Scheduling and Dispatch Surcharge Rate shall equal the rate surcharge that is determined for the applicable period beginning on June 1, 1999, in accordance with Section II of this rule below.

PTF Transmission-Related Local Control Center Scheduling and Dispatch Expense shall equal the PTF transmission related expenses incurred by the PTO from REMVEC II, CONVEX/ESCC, and the Maine Local Control Center as recorded in each PTO's FERC Form 1, Account Nos. 561-561.4, excluding any charges recorded in this account that were incurred under the OATT or Schedule 21 of the OATT. The expenses shall be net of any revenues, as reflected in FERC Account No. 456, received by the PTO for providing scheduling and dispatch services, excluding any revenues recorded in this account that where received as a result of charges under the OATT.

REMVEC II is a Local Control Center of the ISO providing security analysis of PTF.

Local PTF Transmission-Related Scheduling and Dispatch Expense shall equal the sum of (1) each PTO's expenses as recorded in FERC Account Nos. 561-561.4, excluding any ISO and Local Control Center related expenses and any expenses recorded in these accounts, that were incurred under this OATT or the Schedule 21 of this OATT of each PTO as a Transmission Customer, multiplied by the PTF Transmission Plant Allocator, (2) NSTAR Electric Company SCADA-related expenses as calculated in accordance with Appendix A of this Rule, (3) the Central Maine Power Company Local Control Center revenue requirements as calculated in accordance with Appendix B of this Rule, and (4) the CL&P Dispatch Center Revenue Requirement as calculated in accordance with Appendix C of the Rule.

PTF Transmission Plant Allocation Factor is the factor for allocating transmission costs and expenses between PTF and Non-PTF as determined for the applicable period pursuant to Attachment F of the OATT.

II. CALCULATION OF THE SCHEDULING AND DISPATCH SURCHARGE

A. Surcharge for Regional Network Service Customers

For Network Customers, the scheduling and dispatch surcharge for Regional Network Service shall equal the Network Customer's Regional Monthly Network Load, as defined in Section II.21.2 of the OATT,

multiplied by the Monthly Scheduling and Dispatch Surcharge Rate as determined in accordance with Section II.C below.

B. Surcharge for Through or Out Customers

For Through or Out Service Customers, the Scheduling and Dispatch Surcharge shall equal the Transmission Customer's Reserved Capacity for each transaction scheduled for the month multiplied by the applicable Monthly or Hourly Scheduling and Dispatch Surcharge Rate, as determined in accordance with Section II.C below.

C. Scheduling and Dispatch Surcharge Rate

The Scheduling and Dispatch Surcharge Rate will be the surcharge rate in effect from time to time for the applicable period, determined pursuant to the formula described below based on the prior calendar year's data. The Scheduling and Dispatch Surcharge Rate shall be redetermined each year, with the new Surcharge Rate going into effect on June 1 of each year, and be effective for the succeeding twelve months.

In the case of PTOs which are subject to the Commission's jurisdiction, the data used shall be as identified in the PTO's FERC Form 1 report for that year, and shall be based on actual data in lieu of allocated data if specifically identified in the FERC Form 1. When FERC Form 1 data is not the direct source of the data used in the formula, the worksheets used to develop the inputs will reflect Appendix A, Appendix B, and Appendix C of this Rule.

The Scheduling and Dispatch Surcharge Rate shall be equal to the sum of (1) PTF Transmission-Related Local Control Center Scheduling and Dispatch Expense, (2) Local PTF Transmission Related Scheduling and Dispatch Expense, (3) less Schedule 1 revenues from the prior year surcharges for Short-Term Point-To-Point Transactions, and divided by the annual average of the sum of all Regional Network Customers Monthly Peak Load, as defined in Section II.21.2 of the OATT, from the prior calendar year plus the Long-Term Firm Point-To-Point Service Reserved Capacity, from the prior calendar year.

The Monthly Scheduling and Dispatch Surcharge Rate shall equal one-twelfth of the Scheduling and Dispatch Surcharge Rate.

The Hourly Scheduling and Dispatch Surcharge Rate shall be the annual rate divided by 8760.

APPENDIX A TO SCHEDULE 1 IMPLEMENTATION RULE

NSTAR ELECTRIC COMPANY SCADA

This service is required to schedule the movement of power through, out of, within, or into the New England Control Area over Pool Transmission Facilities (PTF). Service under this schedule represents the contribution to that service provided by the PTO's own Dispatch Center, commonly referred to as SCADA. These costs are excluded from costs in Attachment F.

The PTF Revenue Requirement for the scheduling, system control and dispatch service that is based on data for the calendar year 2004 or later shall include an allocated PTF-related amount of Incremental Return and Associated Income Taxes on SCADA-related transmission plant investments included in the Regional System Plan and placed in-service on or after January 1, 2004 (such investments referred to herein as "Post-2003 Dispatch Center Investment"). The Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment shall reflect a surcharge of a 100 basis point ROE adder applicable to certain investment base components as specified in the formula below. The data used in determining the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment shall be based on actual data in lieu of allocated data if specifically identified in NSTAR Electric's accounting records.

Definitions: Dispatch Center Wages and Salaries Allocation Factor: Ratio of Dispatch Center Related Direct Wages and Salaries to NSTAR Electric's total Direct Wages and Salaries excluding Administrative and General Wages and Salaries.

Dispatch Center Plant Allocation Factor: Ratio of Total Investment in Dispatch Center Plant plus Dispatch Center Related General Plant, to Total Plant in service.

Dispatch Center Transmission Plant Allocation Factor: Ratio of Total Investment in Dispatch Center Plant plus Dispatch Center Related General Plant, to Total Investment in Transmission Plant.

The PTF Revenue Requirement for the Scheduling System Control and Dispatch Service shall equal the sum of the PTO's: (A) Return and Associated Income Taxes (including the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment), (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Related Amortization of Investment Tax Credits, (D) Dispatch Center

Related Municipal Tax Expense, (E) Dispatch Center Related Payroll Tax Expense (F) Dispatch Center Operation and Maintenance Expense, and (G) Dispatch Center Related Administrative and General Expense; multiplied by the PTF Transmission Plant Allocation Factor.

The Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment shall be calculated using the Dispatch Center investment base components specifically identified in Section A.1 of the formula below.

A. <u>Return and Associated Income Taxes</u> shall equal the product of the Dispatch Center Investment Base and the Cost of Capital Rate. To calculate the Incremental Return and Associated Income Taxes for Post–2003 Dispatch Center Investment, the Dispatch Center Investment Base will only include items (a), (d) and (e) under Section (A)(1), calculated in the manner indicated.

1. **<u>The Dispatch Center Investment Base</u>** will consist of (a) Dispatch Center Plant in FERC accounts 350-359, plus (b) Dispatch Center Related General Plant, plus (c) Dispatch Center Plant Held for Future Use, less (d) Dispatch Center Related Depreciation Reserve, less (e) Dispatch Center Related Accumulated Deferred Taxes, plus (f) Other Regulatory Assets, plus (g) Dispatch Center Prepayments, plus (h) Dispatch Center Materials and Supplies, plus (i) Dispatch Center Related Cash Working Capital.

a. <u>Dispatch Center Plant</u> will equal the year-end balance of the PTO's Investment in Dispatch Center per FERC accounts 350 through 359. Dispatch Center Plant Investment is not included in PTF investment in the Attachment F revenue requirement. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, Post-2003 Dispatch Center Plant shall be separately identified.

b. <u>Dispatch Center Related General Plant</u> shall equal the PTO's year-end balance of Investment in General Plant multiplied by the Dispatch Center Wages and Salaries Allocation Factor described above.

c. <u>Dispatch Center Plant Held for Future Use</u> shall equal the year-end balance of Transmission related Dispatch Center Investment in FERC account 105.

d. <u>Dispatch Center Related Depreciation Reserve</u> shall equal the year-end balance of Transmission Dispatch Center Depreciation Reserve, plus the year-end balance of

Dispatch Center Related General Depreciation Reserve. Dispatch Center Related General Plant Depreciation Reserve shall equal the product of General Plant Depreciation Reserve and the Dispatch Center Wages and Salaries Allocation Factor described above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, Dispatch Center Depreciation Reserve associated with the Post-2003 Dispatch Center Investment, shall equal the balance of the Dispatch Center Depreciation Reserve multiplied by the ratio of Post-2003 Dispatch Center Plant to total investment in Dispatch Center Plant.

e. Dispatch Center Related Accumulated Deferred Taxes shall equal the year-end balance of Total Accumulated Deferred Income Taxes, multiplied by the Dispatch Center Plant Allocation Factor described above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, Total Accumulated Deferred Income Taxes associated with the Post-2003 Dispatch Center Investment, shall equal the balance of total property-related accumulated deferred income taxes as recorded in FERC Accounts 281 and 282, multiplied by the Dispatch Center Plant Allocation Factor, further multiplied by the ratio of the Post-2003 Dispatch Center Plant to total investment in Dispatch Center Plant.

f. Other Regulatory Assets shall equal the year-end balance of FAS 106 multiplied by the Dispatch Center Wages and Salaries Allocation Factor described in Section (A) (2) (b) above and the year-end balance of FAS 109, net of FAS 109 liability, multiplied by the Dispatch Center Plant Allocation Factor described in above, plus the year-end unamortized balance of merger-related transmission costs recorded in FERC Account No. 182.3 as authorized by FERC multiplied by the Dispatch Center Transmission Plant Allocation Factor.

g. Dispatch Center Prepayments shall equal the year-end balance of Prepayments multiplied by the Dispatch Center Wages and Salaries Allocation Factor described above.

h. Dispatch Center Materials and Supplies shall equal the year-end balance of Transmission Plant Materials and Supplies multiplied times the Dispatch Center Plant Allocation Factor described above.

i. Dispatch Center Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Dispatch Center Transmission Related Operation and Maintenance Expense and Dispatch Center Transmission Related Administrative and General Expense.

2. The Cost of Capital Rate shall equal (a) the Weighted Cost of Capital, plus (b) Federal Income Taxes, plus (c) State Income Taxes.

a. the Weighted Cost of Capital will be calculated based upon the PTO's capital structure at the end of each year and will equal the sum of (i), (ii) and (iii) below.

The Cost of Capital Rate to be used in calculating the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, shall only reflect item (iii) below and shall apply in the manner indicated below.

i. the Long Term Debt Component, which equals the product of the actual weighted average embedded cost to maturity of Long Term Debt then outstanding and the ratio that Long-Term Debt is to Total Capital.

ii. the Preferred Stock Component, which equals the product of the actual weighted average embedded cost to maturity of Preferred Stock then outstanding and the ratio that Preferred Stock is to Total Capital.

iii. the Return on Equity Component, which equals the product of the PTO's Return on Equity as set in the PTO's RNS open access rate and the ratio that Common Equity is to Total Capital. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, the incremental return on equity shall be the product of 1.00% and the ratio of Common Equity to Total Capital.

b. Federal Income Taxes shall equal

$$\frac{A + [(C+B)/D]) \times FT}{1 - FT}$$

Where FT is the Federal Income Tax Rate and A is the sum of the Preferred Stock Component and the Return on Equity Component, as determined in Sections A.2.(a)(ii) and (iii) above, B is Dispatch Center Related Amortization of Investment Tax Credits, as determined in Section II.D. below, C is the Equity AFUDC component of Dispatch Center Depreciation Expense, as defined in Section B., and D is Dispatch Center Investment Base, as determined in A.1., above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, the incremental Federal Income Tax shall equal:

$$(A'*FT)/(1-FT)$$

Where FT is the Federal Income Tax Rate and A' is the incremental return on equity component, as determined in Section A.2.(a)(iii) above.

c. State Income Taxes shall equal

$$\frac{(A + [(C+B)/D] + \text{Federal Income Tax}) \times ST}{1 - ST}$$

Where ST is the State Income Tax Rate and A is the sum of the Preferred Stock Component and the Return on Equity Component, as determined in Section A.2.(a)(ii), and Section A.2.(a)(iii) above, and Federal Income Tax is the rate determined in Section A.2.(b) above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, the incremental State Income Tax shall equal:

$$(A'+ \text{Federal Income Tax})*ST/(1-ST)$$

Where ST is the State Income Tax Rate and A' is the incremental return on equity component, as determined in Section A.2.(a)(iii) above, and Federal Income Tax is the rate determined in Section A.2.(b) above.

B. Dispatch Center Depreciation Expense shall equal the sum of Transmission Depreciation Expense for Dispatch Center Plant, plus an allocation of General Plant Depreciation Expense calculated by multiplying General Plant Depreciation Expense by the Dispatch Center Wages and Salaries Allocation Factor, described in Section (A)(1)(b) above.

C. Dispatch Center Related Amortization of Investment Tax Credits shall equal the PTO's Amortization of Investment Tax Credits multiplied by the Dispatch Center Plant Allocation Factor described above.

D. Dispatch Center Related Municipal Tax Expense shall equal the PTO's total Municipal Tax Expense multiplied by the Dispatch Center Plant Allocation Factor described above.

E. Dispatch Center Related Payroll Tax Expense shall equal the PTO's total electric payroll tax expense, multiplied by the Dispatch Center Wages and Salaries Allocation Factor, described above.

F. Dispatch Center Operation and Maintenance Expense shall equal all expenses related to SCADA operation charged to FERC Account Number 561 through 561.4, excluding any ISO and Local Control Center related expenses and any expenses recorded in this Account that were incurred under this OATT or the Local Service Schedules of this OATT as a Transmission Customer.

G. Dispatch Center Related Administrative and General Expenses shall equal the sum of (1) PTO's Administrative and General Expenses multiplied by the Dispatch Center Wages and Salaries Allocation Factor, (2) Property Insurance multiplied by the Dispatch Center Plant Allocation Factor, and (3) Expenses included in Account 928 (excluding Merger-Related Costs included in Account 928) related to FERC Assessments multiplied by Dispatch Center Plant Allocation Factor, plus any other Federal and State Dispatch Center related expenses or assessments, plus specific Dispatch Center related expenses included in Account 930.1 plus Transmission Merger-Related Costs multiplied by the Dispatch Center Transmission Plant Allocation Factor.

APPENDIX B TO SCHEDULE 1 IMPLEMENTATION RULE CENTRAL MAINE POWER COMPANY LOCAL CONTROL CENTER

I. **DEFINITIONS**

Capitalized terms not otherwise defined in the Tariff and as used in this rule have the following definitions:

A. ALLOCATION FACTORS

1. Wages and Salaries Allocation Factor shall equal the ratio of the Local Control Center Direct Wages and Salaries to total direct wages and salaries excluding administrative and general wages and salaries.

2. Local Control Center Wages and Salaries Allocation Factor shall equal the ratio of the Transmission Local Control Center Direct Wages and Salaries to total Local Control Center Direct Wages and Salaries.

3. Local Control Center PTF Allocation Factor shall equal the ratio of the Local Control Center PTF Direct Wages and Salaries to the total Local Control Center Transmission Direct Wages and Salaries.

4. Local Control Center Plant Allocation Factor shall equal the ratio of the Total Investment in Local Control Center Plant to Total Plant in service.

B. TERMS

Administrative and General Expense shall equal the PTO's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928, and 930.1.

Amortization of Investment Tax Credits shall equal the PTO's credits as recorded in FERC Account No. 411.4

Amortization of Loss on Reacquired Debt shall equal the PTO's expenses as recorded in FERC Account No. 428.1

Other Regulatory Assets/Liabilities -FAS 106 shall equal the net of the PTO's FAS 106 balance as recorded in FERC Account 182.3 and any FAS 106 balance as recorded in the PTO's FERC Account No. 254.

Other Regulatory Assets/Liabilities -FAS 109 shall equal the net of the PTO's FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in the PTO's FERC Account No. 254.

Payroll Taxes shall equal those payroll expenses as recorded in the PTO's FERC Account Nos. 408.1 and 409.1.

Plant Held for Future Use shall equal the PTO's balance in FERC Account No. 105.

Prepayments shall equal the PTO's prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal the PTO's expenses as recorded in FERC Account No. 924.

PTF Local Control Center Direct Wages and Salaries shall equal the PTO's direct wages and salaries related to providing PTF Local Control Center services as recorded in FERC Account No. 561.

Local Control Center Direct Wages and Salaries shall equal the PTO's direct wages and salaries related to providing Local Control Center services as recorded in FERC Account Nos. 556, 561-561.4, and 581.

Local Control Center Operation and Maintenance Expense shall equal the PTO's expenses recorded in FERC Account Nos. 556, 561-561.4, & 581, less any costs included in FERC Account Nos. 561-561.4 that are otherwise recoverable pursuant to Subpart (1) of the Local PTF Transmission Related Scheduling and Dispatch Expense of the rule implementing the Schedule 1 rate surcharge of the OATT.

Local Control Center Plant Depreciation Reserve shall equal the PTO's depreciation reserve balance for Local Control Center Related Plant as recorded in FERC Account No. 108.

Materials and Supplies shall equal the PTO's balance as recorded in FERC Account No. 154.

Local Control Center Related Depreciation Expense shall equal the PTO's depreciation expense for Local Control Center Related Plant as recorded in FERC Account No. 403.

Local Control Center Related Plant shall equal the PTO's gross plant balances used for system control and dispatch purposes as recorded in FERC Account Nos. 303-399. To the extent that such plant includes any amounts recorded as transmission investment in FERC Account Nos. 350-359, such amounts will be excluded for purposes of determining annual transmission revenue requirements pursuant to the billing rule which implements Attachment F of the OATT.

Local Control Center Support Revenues shall equal the revenues received from Local Control Center supporters as recorded in FERC Account Nos. 454 and 456, excluding any revenues received under Schedule 1 of the OATT or the PTO's Local Service Schedule.

Total Accumulated Deferred Income Taxes shall equal the net of the deferred tax balances as recorded in FERC Account Nos. 281-283 and 190.

Total Loss on Reacquired Debt shall equal the PTO's balance as recorded in FERC Account No. 189.

Total Municipal Tax Expense shall equal the PTO's municipal tax expenses as recorded in FERC Account Nos. 408.1 and 409.1.

Total Plant in Service shall equal the PTO's total gross plant balance as recorded in FERC Account Nos. 301-399.

Transmission Local Control Center Direct Wages and Salaries shall equal the PTO's direct wages and salaries related to providing Local Control Center services as recorded in FERC Account No. 561-561.4.

II. CALCULATION OF TOTAL LOCAL CONTROL CENTER REVENUE REQUIREMENTS

The Local Control Center Revenue Requirements based on data for calendar year 2004 or later shall include an Incremental Return and Associated Income Taxes on Central Maine's local control center investments

included in the Regional System Plan and placed in service on or after January 1, 2004 (such investments referred to herein as "Post-2003 Investment"). The Incremental Return and Associated Income Taxes for Post-2003 Investment shall reflect a surcharge of a 100 basis point ROE adder applicable to certain investment base components as specified in the formula below. The data used in determining the Incremental Return and Associated Income Taxes for Post-2003 Investment shall be based on actual data in lieu of allocated data if specifically identified in Central Maine's accounting records.

The Local Control Center Revenue Requirement shall equal the sum of the Local Control Center related (A) Return and Associated Income Taxes (including the Incremental Return and Associated Income Taxes for Post-2003 Investment), (B) Depreciation Expense, (C) Amortization of Loss on Reacquired Debt, (D) Amortization of Investment Tax Credits, (E) Municipal Tax Expense, (F) Payroll Tax Expense, (G) Operations and Maintenance Expense, (H) Administrative and General, minus (I) Support Revenues.

The Incremental Return and Associated Income Taxes for Post-2003 Investment shall be calculated using the investment base components specifically identified in Section A.1. of the formula below.

A. <u>Return and Associated Income Taxes</u> shall equal the product of the Local Control Center Investment Base and the Cost of Capital Rate reflected in the PTO's Attachment F formula of the OATT. To calculate the Incremental Return and Associated Income Taxes for Post 2003 Investment, Local Control Center Investment Base shall only include Sections II.A.1.(a), (b), and (c), in the manner indicated.

1. <u>Local Control Center Investment Base</u>

The Local Control Center Investment Base will be the year end balances of Local Control Center related: (a) Plant, plus (b) Plant Held for Future Use, less (c) Depreciation Reserve, less (d) Accumulated Deferred Taxes, plus (e) Loss on Reacquired Debt, plus (f) Other Regulatory Assets/Liabilities, plus (g) prepayments, plus (h) Materials and Supplies, plus (i) Cash Working Capital.

(a) <u>Local Control Center Related Plant</u> shall equal the balance of the PTO's Investment in Local Control Center Plant. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Investment, Post 2003 Local Control Center Plant shall be separately identified.

(b) Local Control Center Related Plant Held for Future Use shall equal the balance of Plant Held for Future Use multiplied by the Local Control Center Plant Allocation Factor.

(c) Local Control Center Related Depreciation Reserve shall equal the Depreciation Reserve for the PTO's investment in Local Control Center plant. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Investment, Local Control Center Depreciation Reserve shall equal the Depreciation Reserve for the PTO's Local Control Center Plant identified in (a) above.

(d) Local Control Center Related Accumulated Deferred Taxes shall equal the PTO's electric balance of Accumulated Deferred Income Taxes multiplied by the Local Control Center Plant Allocation Factor. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Investment, Local Control Center Accumulated Deferred Taxes shall equal the PTO's balance of total property related accumulated deferred income taxes recorded in FERC account 281and 282 multiplied by the Local Control Center Plant Allocation Factor and further multiplied by the ratio of Post-2003 Investment to Total Local Control Center Related Plant.

(e) Local Control Center Related Loss on Reacquired Debt shall equal the PTO's electric balance of Total Loss on Reacquired Debt multiplied by the Local Control Center Plant Allocation Factor.

(f) Local Control Center Related Other Regulatory Assets/Liabilities shall equal the PTO's electric balance of any deferred recovery of FAS 106 expenses multiplied by the Local Control Center Wages and Salaries Allocation Factor, plus the PTO's electric balance of FAS 109 multiplied by the Local Control Center Plant Allocation Factor.

(g) Local Control Center Related Prepayments shall equal the PTO's electric balance of prepayments multiplied by the Local Control Center Plant Allocation Factor.

(h) Local Control Center Related Materials and Supplies shall equal the PTO's electric balance of Plant Materials and Supplies, multiplied by the Local Control Center Plant Allocation Factor.

(i) Local Control Center Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Local Control Center Operation and Maintenance Expense, Local Control Center Related Administrative and General Expense.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) the PTO's Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon the capital structure at the end of each year and will equal the sum of (i),(ii), and (iii) below. The Cost of Capital Rate to be used in calculating the Incremental Return and Associated Income Taxes for Post-2003 Investment shall only reflect item (iii) below and shall apply in the manner indicated below

(b) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity of the PTO's long-term debt then outstanding and the ratio that long-term debt is to the PTO's total capital.

(c) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of the PTO's preferred stock then outstanding and the ratio that preferred stock is to the PTO's total capital.

(d) the return on equity component, which equals the product of the PTO's Return on Equity as set in the PTO's RNS open access rate and the ratio that common equity is to the PTO's total capital. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Investment, the incremental return on equity shall be the product of Central Maine's incremental return on equity of 1.0% and the ratio that common equity is to the PTO's total capital.

(e) Federal Income Tax shall equal

$$\frac{(A+[(C+B)/D]) \times FT}{1 - FT}$$

Where FT is the Federal Income Tax Rate and A is the sum of the preferred stock component and the return on equity component, as determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section II.D. below, C is the equity AFUDC component of Local Control Center Depreciation Expense, as defined in II.B., and D is Local Control Center Investment Base, as determined in II.A.1., above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Investment, the incremental Federal Income Tax shall equal

$$\frac{(A' * FT)}{(1 - FT)}$$

where FT is the Federal Income Tax Rate and A' is the incremental return on equity component, as determined in Section II.A.2.(a)(iii) above.

(f) <u>State Income Tax</u> shall equal

$$\frac{(A+[(C+B)/D] + \text{Federal Income Tax}) \times ST}{1 - ST}$$

Where ST is the State Income Tax Rate, A is the sum of the preferred stock component and return on equity component determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section II.D. below, C is the equity AFUDC component of Local Control Center Depreciation Expense, as defined in II.B., D is the Local Control Center Investment Base, as determined in II.A.1., above and Federal Income Tax is the rate determined in Section II.A.1.(b) above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Investment, the incremental State Income Tax shall equal

$$\frac{(A' + \text{Federal Income Tax})(ST)}{(1 - ST)}$$

where ST is the State Income Tax Rate, A' is the incremental return on equity component determined in Section II.A.2.(a)(iii) above, and Federal Income Tax is the rate determined in Section II.A.2.(b) above.

B. <u>Local Control Center Depreciation Expense</u> shall equal the Local Control Center Plant Depreciation Expense and Accumulated Amortization.

C. Local Control Center Related Amortization of Loss on Reacquired Debt shall equal the PTO's electric balance of Loss on Reacquired Debt multiplied by the Local Control Center Plant Allocation Factor.

D. Local Control Center Related Amortization of Investment Tax Credits shall equal the PTO's electric Amortization of Investment Tax Credits multiplied by the Local Control Center Plant Allocation Factor.

E. Local Control Center Related Municipal Tax Expense shall equal the PTO's total electric municipal tax expense multiplied by the Local Control Center Plant Allocation Factor.

F. Local Control Center Related Payroll Tax Expense shall equal the PTO's total electric payroll tax expense, multiplied by the Wages and Salaries Allocation Factor.

G. Local Control Center Operation and Maintenance Expense shall equal the PTO's Operation and Maintenance Expenses recorded in FERC Account Nos. 556, 561-561.4, and 581, less any costs included in FERC Account Nos. 561-561.4 that are otherwise recoverable pursuant to Subpart (1) of Local PTF Transmission Related Scheduling and Dispatch Expense of the rule implementing the Schedule 1 rate surcharge of the OATT.

H. Local Control Center Related Administrative and General Expenses shall equal the sum of (1) PTO's Administrative and General Expenses multiplied by the Wages and Salaries Allocation Factor, (2) Property Insurance multiplied by the Local Control Center Plant Allocation Factor, and (3) Expenses included in Account 928 related to FERC Assessments multiplied by the Local Control Center Plant Allocation Factor, plus any other Federal and State Local Control Center related expenses or assessments, plus specific Local Control Center related expenses included in Account 930.1.

I. Transmission Support Revenues shall equal the PTO's revenue received for providing system control and dispatch service.

III. CALCULATION OF LOCAL CONTROL CENTER TRANSMISSION REVENUE REQUIREMENTS

The Total Local Control Center Revenue Requirements derived in Section II. above are further multiplied by the Local Control Center Wages and Salaries Allocation Factor defined in Section I. A. 2. above to determine the transmission related revenue requirement, and further multiplied by the Local Control Center PTF Allocation Factor defined in Section I. A. 3. above, to determine the PTF Transmission related revenue requirements to be included in Schedule I of the OATT.

APPENDIX C TO SCHEDULE 1 IMPLEMENTATION RULE
CL&P DISPATCH CENTER REVENUE REQUIREMENT

This appendix calculates the CL&P Dispatch Center Revenue Requirement for use in calculating part (4) of the Local PTF Transmission-Related Scheduling and Dispatch expenses in the Schedule 1 Implementation Rule. The CL&P Dispatch Center Revenue Requirement for use during a calendar year shall be based on CL&P's costs for the immediately preceding calendar year.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section II.1 of the OATT and as used in this appendix have the following definitions:

Dispatch Center means CL&P's CONVEX dispatch center.

Dispatch Center Plant shall equal CL&P's year-end gross plant balances used for CL&P's Dispatch Center as recorded in FERC Account Nos. 303, 350-359, and 389-399.

Dispatch Center Depreciation Reserve shall equal CL&P's year-end depreciation reserve balance for Dispatch Center Plant as recorded in FERC Account No. 108. Dispatch Center Accumulated Deferred Income Taxes shall equal the net of CL&P's year-end deferred tax balances for Dispatch center Plant as recorded in FERC Account Nos. 281-283 and 190.

II. CALCULATION OF TOTAL DISPATCH CENTER REVENUE REQUIREMENT

The Dispatch Center Revenue Requirement shall equal the sum of (A) Dispatch Center Return and Associated Income Taxes, (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Amortization of Investment Tax Credits, and (D) Dispatch Center Municipal Tax Expense; provided, that during the period June 1, 2008 through May 31, 2009, the Dispatch Center Revenue Requirement shall equal the product of (i) the number of months (or fractions thereof) remaining in 2007 on and after the date upon which the Convex Agreements are permitted to be made effective by FERC, divided by 12 and (ii) the sum of (A) Dispatch Center Return and Associated Income Taxes, (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Amortization of Investment Tax Credits, and (D) Dispatch Center Municipal Tax Expense. "CONVEX Agreements" refers to the agreements between The Connecticut Light & Power Company and

various entities relating to the operation of the Dispatch Center and filed with FERC contemporaneously with the filing of this Appendix C.

A. Dispatch Center Return and Associated Income Taxes shall equal the product of the Dispatch Center Investment Base and the Cost of Capital Rate.

1. Dispatch Center Investment Base

The Dispatch Center Investment Base will be the year-end balances of:

(a) Dispatch Center Plant, less (b) Dispatch Center Depreciation Reserve, less (c) Dispatch Center Accumulated Deferred Income Taxes.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) the Weighted Cost of Capital, plus (b) Federal Income Tax, plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon CL&P's capital structure at the end of each year and will equal the sum of (i), (ii), and (iii) below.

(i) The long-term debt component, which equals the product of the year-end balance of CL&P's first mortgage bonds and pollution control notes adjusted for premiums, discounts, debt expense and losses on reacquired debt and the ratio of the long term debt to CL&P's total capital.

(ii) The preferred stock component, which equals the product of the year-end balance of CL&P's preferred stock adjusted for premiums, discounts and unamortized issue expense and the ratio of the preferred stock to CL&P's total capital.

(iii) The common equity component, which equals the product of 10.3% and the ratio of the common equity to CL&P's total capital.

(b and c) Federal and State Income Taxes shall be computed as follows:

AxBxC

where: A = Dispatch Center Investment Base

B = Cost of equity capital (the sum of the preferred stock component and common equity component)

C = TC/(1-TE), where TE is the effective combined federal and state statutory income tax rates in effect at the applicable time.

B. Dispatch Center Depreciation Expense shall equal CL&P's Dispatch Center depreciation expense as recorded in FERC Account No. 403.

C. Dispatch Center Amortization of Investment Tax Credits shall equal CL&P's Dispatch Center amortization of investment tax credits as recorded in FERC Account No. 411.1.

D. Dispatch Center Municipal Tax Expense shall equal CL&P's Dispatch Center municipal tax expense as recorded in FERC Account Nos. 408.1 and 409.1.

SCHEDULE 21 - NSTAR

NSTAR ELECTRIC COMPANY
LOCAL SERVICE SCHEDULE

I COMMON SERVICE PROVISIONS

1.0 DEFINITIONS

Whenever used in this Local Service Schedule, in either the singular or plural number, the following capitalized terms shall have the meanings specified in this Section 1. Terms used in this Local Service Schedule that are not defined in this Local Service Schedule shall have the meanings set forth in the Tariff or customarily attributed to such terms by the electric utility industry in New England. Where there is a conflict between this Local Service Schedule and the Tariff, the terms here shall apply.

1.1 Annual Transmission Revenue Requirements

The total annual cost of the Transmission System shall be the amount specified in Attachment D until amended by NSTAR or modified by the Commission.

1.2 Annual True-Up

The reconciliation to actual costs of the estimated costs used for billing purposes under Section 4.0 of this Local Service Schedule for any Service Year.

1.3 Designated Agent

Any entity that performs actions or functions on behalf of NSTAR, an Eligible Customer, or the Transmission Customer required under the Local Service Schedule.

1.4 Firm Local Point-To-Point Service

Transmission service under this Local Service Schedule that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to this Local Service Schedule.

1.5 Load Ratio Share

Ratio of a Transmission Customer's most recently reported Monthly Network Load in the case of Network Customers and including, where applicable, the Reserved Capacity of Transmission Customers taking Firm Local Point-To-Point Service, to the total load of Network Customers and the Reserved Capacity of Transmission Customers taking Firm Local Point-To-Point Service.

1.6 Local Network

All transmission facilities constituting NSTAR's non-Pool Transmission Facilities (Non-PTF), excluding the Phase I/II HVDC-TF, which is defined in Schedule 20A of this OATT.

1.7 Local Network Load

The load that a Network Customer designates for Local Network Service under this Local Service Schedule. The Network Customer's Local Network Load shall include all load designated by the Network Customer, (including losses). A Network Customer may elect to designate less than its total load as Local Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete Points of Delivery as Local Network Load, the Eligible Customer is responsible for making separate arrangements under this Local Service Schedule for any Local Point-To-Point Service that may be necessary for such non-designated load.

1.8 Local Network Service

The transmission service provided under this Local Service Schedule over NSTAR's Local Network.

1.9 Local Network Upgrades

Modifications or additions to transmission-related facilities that are integrated with and support NSTAR's overall Transmission System for the general benefit of all users of such Transmission System.

1.10 Local Point-To-Point Service

The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under this Local Service Schedule over NSTAR's Local Network.

1.11 Long-Term Firm Local Point-To-Point Service

Firm Local Point-To-Point Service provided under this Local Service Schedule with a term of one year or more.

1.12 Monthly Network Load

A Network Customer's hourly load (including its designated Local Network Load not physically interconnected with NSTAR under Section 15.2 of this Local Service Schedule) coincident with NSTAR's Monthly Transmission System Peak.

1.13 Native Load Customers

The wholesale and retail power customers of NSTAR on whose behalf NSTAR, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate NSTAR's system to meet the reliable electric needs of such customers.

1.14 NERC

North American Electric Reliability Council, the Electric Reliability Organization of the United States.

1.15 Non-Firm Local Point-To-Point Service

Local Point-To-Point Service under this Local Service Schedule that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in this Local Service Schedule. Non-Firm Local Point-To-Point Service is available on a stand-alone basis for periods ranging from one hour to one month.

1.16 NPCC

Northeast Power Coordinating Council, a regional reliability council of NERC.

1.17 NSTAR

NSTAR Electric Company, a Massachusetts Corporation with offices located at 800 Boylston Street, Boston, Massachusetts 02199. NSTAR owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce and provides service pursuant to the rates, terms and conditions of this Local Service Schedule and the applicable terms and conditions of this Local Service Schedule.

1.18 NSTAR's Monthly Transmission System Load

NSTAR's Monthly Transmission System Peak minus the coincident peak usage of all Firm Local Point-To-Point Service customers pursuant to Part II of this Local Service Schedule plus the Reserved Capacity of all Firm Local Point-To-Point Service customers.

1.19 NSTAR's Monthly Transmission System Peak

The maximum firm usage of NSTAR's Transmission System in a calendar month.

1.20 Parties

NSTAR and the Transmission Customer receiving service under this Local Service Schedule.

1.21 Point(s) of Delivery

Point(s) on NSTAR's Transmission System where capacity and energy transmitted by NSTAR will be made available to the Receiving Party under this Local Service Schedule. The Point(s) of Delivery shall be specified in the Transmission Service Agreement.

1.22 Point(s) of Receipt

Point(s) of interconnection on NSTAR's Transmission System where capacity and energy will be made available to NSTAR by the Delivering Party under this Local Service Schedule. The Point(s) of Receipt shall be specified in the Transmission Service Agreement.

1.23 Service Year

The calendar year in which the Transmission Customer is receiving service under this Local Service Schedule.

1.24 Short-Term Firm Local Point-To-Point Service

Firm Local Point-To-Point Service under this Local Service Schedule with a term of less than one year.

1.25 Transmission System

The facilities owned, controlled or operated by NSTAR that are used to provide transmission service under this Local Service Schedule.

2.0 ANCILLARY SERVICES

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. NSTAR is required to provide and the Transmission Customer is required to purchase the following Ancillary Services (i) Scheduling, System Control and Dispatch, and (ii) Supplemental End-Use Reactive Support Service.

In addition, the Transmission Customer is required to purchase additional Ancillary Services under the terms and conditions of the Tariff. The Transmission Customer may not decline the Transmission Provider's offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it

will purchase from the Transmission Provider. A Transmission Customer that exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or an Eligible Customer that uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved is required to pay for all of the Ancillary Services identified in this section that were provided by the Transmission Provider associated with the unreserved service. The Transmission Customer or Eligible Customer will pay for Ancillary Services based on the amount of transmission service it used but did not reserve. NSTAR shall also assess a penalty for any unauthorized use of Ancillary Services by the Transmission Customer, based on the amount of transmission service it used but did not reserve, using the rate shown for such Ancillary Service.

The prices and/or compensation methods for Local System Control and Dispatch Services and Supplemental End-Use Reactive Support Service are described in Attachment D and Schedule 2, respectively, attached to and made a part of this Local Service Schedule. Three principal requirements apply to discounts for Ancillary Services provided by NSTAR in conjunction with its provision of transmission service as follows: (1) any offer of a discount made by NSTAR must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. A discount agreed upon for an Ancillary Service must be offered for the same period to all Eligible Customers on NSTAR's system.

3.0 CREDITWORTHINESS

NSTAR's creditworthiness procedures are specified in Attachment L to this Local Service Schedule.

4.0 BILLING AND PAYMENT

4.1 Billing Procedure

Within a reasonable time after the first day of each month, NSTAR shall submit an invoice to the Transmission Customer for the charges for all services furnished under this Local Service Schedule during the preceding month. The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to NSTAR, or by wire transfer to a bank named by NSTAR.

Billings hereunder shall be based on cost estimates made by NSTAR subject to Annual True-up

when actual costs for the Service Year are known. Such Annual True-up shall occur no later than six (6) months after the close of the Service Year to which the Annual True-up relates. To the extent bill adjustments are required pursuant to the Annual True-up, such adjustments shall bear interest calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii).

(i) The Annual True-Up shall be performed by recalculation of the costs for the Service Year based on actual cost and load information as reported in the FERC Form 1 for that Service Year and shall develop thereby an Embedded Cost Charge, defined in Section 16.1, to be used in the said Annual True-Up. The Annual True-Up shall also include the CWIP Supplement referred to in clause (ix).

(ii) The Annual True-Up will be filed with FERC by NSTAR in an informational filing on or before May 31 of the year following the Service Year and posted on NSTAR's website. The Annual True-Up so filed and posted shall include the actual report showing the basis for the computation of the Postretirement Benefits Other Than Pensions ("PBOP") component of "Administrative and General Expense" and shall also show the basis for the allocation of the PBOP expense to the service provided under this Local Service Schedule; provided that the information so filed and posted shall not include confidential information. The informational filing shall include a Benefits Labor Loader showing the basis for such allocation of both PBOP and prepaid pension costs. On request, NSTAR shall provide any Network Customer the Annual True-Up by May 31 of the year following the Service Year. Any difference between the estimated Embedded Cost Charge and the actual Embedded Cost Charge shall be collected from or refunded to the Network Customer in the month of June of the calendar year following the Service Year.

(iii) The Annual True-Up provided pursuant to Section 4.1(ii) shall include an attestation by a Company officer that "to the best of the affiant's knowledge, information and belief the data employed in the Annual True-Up reflect NSTAR's per book costs for the Service Year, conform to NSTAR's FERC Form 1 Report for the Service Year, conform in all material respects to the FERC Uniform System of Accounts, and have been developed in accordance with the provisions of this rate schedule."

(iv) The Annual True-Up shall also be accompanied by supplementary information which

shall (i) detail any data used in the Annual True-Up not directly taken from NSTAR's FERC Form 1 Report and (ii) identify any FERC Form 1 Account used to record expenses during the Service Year that was not used in the preceding Service Year. The supplementary information shall be certified by an officer of NSTAR.

(v) There shall be an "Audit Period" that will extend from July 1 through September 30 of the year following the Service Year; provided that NSTAR and the Network Customer may agree to extend the Audit Period beyond September 30 by their mutual written agreement. During the Audit Period, any Network Customer shall have the right to conduct an audit or other inspection of the actual data used in the Annual True-Up and/or request additional information not included with the Annual True-Up. NSTAR shall not withhold information, including PBOP information, on grounds of confidentiality, but is entitled to make such information available pursuant to a confidentiality agreement and to restrict access to non-competitive duty personnel and to other personnel whose receipt of the information would not be in violation of the Standards and/or Code of Conduct as prescribed by FERC. During the Audit Period, NSTAR shall exercise all commercially reasonable efforts to provide the Network Customer, within 10 business days, such additional information as the Network Customer may request in order to understand the Annual True-Up. To the extent requested, NSTAR shall meet with any Network Customer to provide such additional information, explanation, and/or clarification regarding the Annual True-Up as the Network Customer may request.

(vi) During the Audit Period, the Network Customer shall have the right to request NSTAR to adjust the Annual True-Up, and any refunds it received or payments it made, pursuant to the Annual True-Up to the extent of any discrepancy between the data employed by NSTAR in performing the Annual True-Up and the actual data for the Service Year or in the event NSTAR developed the Annual True-Up in a manner that is inconsistent with this rate schedule.

(vii) If NSTAR does not agree to the Network Customer's request, as set forth in subparagraph (vi), and if NSTAR and the Network Customer are in disagreement as to any component of the Annual True-Up, the Network Customer within thirty days following the conclusion of the Audit Period may request and NSTAR shall agree to non-binding dispute resolution either conducted with the FERC Staff or otherwise at the Network Customer's choice. The Network Customer may file a complaint with the Commission within thirty days following completion of the audit period or the dispute resolution process and shall specify in that

complaint the component or components of the Annual True Up that the Network Customer disputes. In the event such a complaint is filed, the disputed component or components of the Annual True Up shall be subject to refund as of the first day of the Service Year pending the results of the Commission investigation instituted as a result of such complaint. If the Network Customer fails to object to the Annual True-Up within thirty days following conclusion of the Audit Period, NSTAR's costs for the Service Year shall be deemed final, and its revenues from the Network Customer for the Service Year shall not be subject to refund; provided that the deadline for such an objection shall (i) be extended for ninety days following the date NSTAR makes any subsequent change to its Form 1 data for the Service Year that affects the Annual True-Up and (ii) shall not apply if the Commission prior to December 31st of the calendar year following the Service Year institutes its own investigation of NSTAR's Service Year costs.

(viii) Subject to the limitation that the Massachusetts Attorney General does not make or receive transmission payments or refunds, the Massachusetts Attorney General shall have the same procedural rights under this Section 4.0 as a Network Customer. This in no way obligates the Massachusetts Attorney General to the dispute resolution or arbitration procedures outlined in Sections 5.1 and 5.2.

(ix) The Annual True-Up shall include a CWIP Supplement, which shall apply to the Service Year, shall be filed with FERC by NSTAR in an informational filing on or before June 30 of the year following the Service Year and posted on NSTAR's website to the extent it does not include critical energy infrastructure information or other confidential information. The CWIP Supplement shall include NSTAR Electric's most recent annual construction forecast. The CWIP Supplement shall provide for each project included in rate base during the Service Year the actual amounts of CWIP recorded for each project, the related accounts, such as AFUDC and regulatory liability, inclusive of all subaccounts, and the resulting effect on the CWIP revenue requirement in line item detail. The CWIP Supplement shall also identify any changes in NSTAR's accounting practices related to the accrual of AFUDC and the inclusion of CWIP in rate base or related to ensuring that AFUDC is not accrued on CWIP balances that have been included in rate base.

For each "new project" (a project that is estimated to enter rate base for the first time in the Service Year), the CWIP Supplement shall provide, to the extent not included in the construction forecast, a detailed statement of the reasons for undertaking the project, the benefits to be derived

from the project, and the alternatives to or consequences of not undertaking the project. For each "pre-existing project" (a project that entered rate base prior to the Service Year), the CWIP Supplement shall include an update on the status of the project including any material change regarding the estimated cost of the project, the estimated in-service date and/or project timelines, and whether there is any change in the need for the project or in alternatives to the project. CWIP associated with a project cannot be included in the rate base for a Service Year unless it is included in the CWIP Supplement applicable to the Service Year.

The CWIP Supplement applicable to a Service Year shall include a CWIP Work Order/Project Reference Aid ("Reference Aid") that distinguishes between new projects and pre-existing projects and that provides for each project, whether new or pre-existing, ISO information, to the extent such information is available and applies to a project, and NSTAR information. The ISO information shall include a short description of the project, the year the project was approved through the ISO process, and the project identification number for ISO purposes. The NSTAR information shall include reference to the most recent NSTAR construction planning forecast in which the project appeared, the page of the plan at which the project description begins, the NSTAR numeric project designation, the NSTAR description of the project, the work order or work orders associated with the project, and a description of each work order. The Reference Aid shall present this information in a format so that the ISO information related to a project can be correlated with the NSTAR information related to a project. The Reference Aid, as described above, is based on current ISO and NSTAR tracking systems for projects under or proposed for construction and is to be modified to present equivalent information if and to the extent the ISO and/or NSTAR tracking system is modified.

The 50% of transmission-related CWIP included in rate base is subject to the Annual True-Up and dispute resolution provisions of this Section 4.1 regarding differences between actual and estimated costs. In addition, the CWIP included in rate base for a project shall be subject to refund as provided below to the extent the Commission makes a finding that the inclusion of such CWIP in rate base is unjust and unreasonable. In the case of a new project, the refund amount shall be the CWIP actually recovered from customers from the date of collection to the date of refund. In any proceeding regarding a new project, NSTAR shall bear the burden of proving that inclusion of CWIP related to the new project in rate base is just and reasonable. In the case of a pre-existing project, the refund amount shall be for the CWIP actually recovered from customers from the prospective refund effective date specified by the Commission pursuant to the

provisions of Section 206 of the Federal Power Act to the date of refund. All refunds shall include interest at the rate specified in 18 C.F.R. § 35.19a(a)(2)(iii). Any customer and/or the Massachusetts Attorney General can request that the Commission institute an investigation into the justness and reasonableness of including CWIP for any project in rate base and the Commission may institute such an investigation sua sponte.

Nothing in this Clause (ix) authorizes the inclusion in rate base of more than 50% of the CWIP balance attributable to a project. Absent a Commission finding of imprudence, NSTAR shall be entitled to accrue AFUDC as to any CWIP that is excluded from rate base. The Commission's institution of an investigation as to the justness and reasonableness of including CWIP associated with a project in rate base does not affect the timing or the finality of other components of the Annual True-Up as established by clause (vii) hereof.

With the exception of curtailment penalty charges pursuant to Section 16.2 and Schedule 3, paragraph 5 and Schedule 4, paragraph 6, any Annual True-Up rendered under this Local Service Schedule and any other monthly bill to which the Annual True-Up relates shall be binding on both Parties one (1) year from the date of NSTAR's Annual True-Up, unless previously disputed pursuant to this section or Section 4.3 of this Local Service Schedule.

4.2 Interest on Unpaid Balances

Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by NSTAR.

4.3 Customer Default

In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to NSTAR on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after NSTAR notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, NSTAR may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request.

In the event of a billing dispute between NSTAR and the Transmission Customer, NSTAR will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then NSTAR may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

5.0 DISPUTE RESOLUTION PROCEDURES

5.1 Internal Dispute Resolution Procedures

Any dispute between a Transmission Customer and NSTAR involving transmission service under this Local Service Schedule (excluding applications for rate changes or other changes to this Local Service Schedule, or to any Service Agreement entered into under this Local Service Schedule, which shall be presented directly to the Commission for resolution) shall be referred to a designated senior representative of NSTAR and a senior representative of the Transmission Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days [or such other period as the Parties may agree upon] by mutual agreement, such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below.

5.2 External Arbitration Procedures

Any arbitration initiated under this Local Service Schedule shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) days of the referral of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association and any applicable Commission regulations or ISO rules.

5.3 Arbitration Decisions

Unless otherwise agreed, the arbitrator(s) shall render a decision within ninety (90) days of appointment and shall notify the Parties in writing of such decision and the reasons therefore. The arbitrator(s) shall be authorized only to interpret and apply the provisions of this Local Service Schedule and any Service Agreement entered into under this Local Service Schedule and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act and/or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with the Commission if it affects jurisdictional rates, terms and conditions of service or facilities.

5.4 Costs

Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable:

(a) the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or

(b) one half the cost of the single arbitrator jointly chosen by the Parties.

5.5 Rights Under The Federal Power Act

Nothing in this section shall restrict the rights of any party to file a complaint with the Commission under relevant provisions of the Federal Power Act.

II LOCAL POINT-TO-POINT SERVICE

6.0 NATURE OF FIRM LOCAL POINT-TO-POINT SERVICE

6.1 Curtailment of Firm Local Point-To-Point Service

In the event a Transmission Customer (including Third-Party Sales by NSTAR) fails to curtail a transaction when requested to do so by NSTAR, the Local Control Center and/or ISO, as

appropriate and pursuant to this Section, NSTAR shall assess a penalty charge to the Transmission Customer. Said penalty charge will be determined in accordance with this Local Service Schedule.

In the event NSTAR, the Local Control Center or ISO exercises their rights to effect a Curtailment, in whole or in part, of Firm Local Point-To-Point Service, no credit or other adjustment shall be provided as a result of the Curtailment with respect to the charge payable by the Transmission Customer.

6.2 Classification of Firm Local Point-To-Point Service

(a) The Transmission Customer taking Firm Local Point-To-Point Service may, (1) change its Points of Receipt and Delivery to obtain service on a non-firm basis consistent with the terms of Part I, Section 10(a) of Schedule 21 of the OATT or (2) request a modification of the Points of Receipt or Delivery on a firm basis pursuant to the terms of Part I, Section 10(b) of Schedule 21 of the OATT; provided that NSTAR continues to be compensated for any costs associated with the construction or upgrading of facilities associated with the original firm service.

(b) In the event that a Transmission Customer's use of the Transmission System (including Third-Party Sales by NSTAR) exceeds that Transmission Customer's Reserved Capacity at any Point of Receipt or Point of Delivery in any hour, NSTAR will charge the Transmission Customer a penalty charge in accordance with Section 10 and Schedule 3 of this Local Service Schedule.

(c) Under no circumstance will NSTAR be obligated to provide Control Area Ancillary Services to the Transmission Customer in support of any excess capacity (i.e., capacity in excess of Transmission Customer's Reserved Capacity).

7.0 NATURE OF NON-FIRM LOCAL POINT-TO-POINT SERVICE

7.1 Classification of Non-Firm Local Point-To-Point Service

In the event that a Transmission Customer's use of the Transmission System (including Third-Party Sales by NSTAR) exceeds that Transmission Customer's non-firm Reserved Capacity at any Point of Receipt or Point of Delivery, NSTAR will charge the Transmission

Customer a penalty charge in accordance with Section 10 and Schedule 4 of this Local Service Schedule for such excess. Under no circumstance will NSTAR be obligated to provide Control Area Ancillary Services to the Transmission Customer in support of any excess capacity (i.e., capacity in excess of Transmission Customer's Reserved Capacity).

7.2 Curtailment or Interruption of Service

In the event a Transmission Customer (including Third-Party Sales by NSTAR) fails to implement a Curtailment or Interruption when requested to do so by NSTAR, the Local Control Center and/or ISO, as appropriate and pursuant to this Section, NSTAR shall assess a penalty charge. Said penalty charge will be determined in accordance with Section 10 and Schedule 4 of this Local Service Schedule.

In the event NSTAR, the Local Control Center and/or ISO exercises its rights to effect a Curtailment, in whole or part, of Non-Firm Local Point-To-Point Service, no credit or other adjustment shall be provided as a result of the Curtailment with respect to the charge payable by the Transmission Customer.

In the event NSTAR, the Local Control Center and/or ISO exercises its rights to effect an Interruption, in whole or part, of Non-Firm Local Point-To-Point Service, the charge payable by the Transmission Customer shall be computed as if the term of service actually rendered were the term of service reserved; provided that an adjustment of the charge shall be made only when the Interruption is initiated by NSTAR, the Local Control Center and/or ISO, not when the customer fails to deliver energy to NSTAR.

8.0 SERVICE AVAILABILITY

8.1 Real Power Losses

Real power losses associated with transactions on NSTAR's Local Network shall be determined based on estimated average system losses for metering points on NSTAR's Local Network; the loss factor will be three and one tenth percent (3.1%).

8.2 Load Shedding

To the extent that a system contingency exists on the NSTAR Transmission System or the New England Transmission System and NSTAR, the Local Control Center or ISO, as appropriate,

determines that it is necessary to shed load, the Parties shall shed load in accordance with the procedures specified by NSTAR, the Local Control Center and/or ISO.

9.0 METERING

Unless otherwise agreed, the Transmission Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted under the Local Service Schedule and to communicate the information to NSTAR. However, NSTAR reserves the right to determine and approve any and all metering equipment and the metering installation design, such approval not to be unreasonably withheld.

All meters, including any recording devices or telemetry equipment must be operated and maintained in accordance with ISO Operating Procedures. Unless otherwise agreed, such equipment shall remain the property of NSTAR.

If at any time any metering equipment owned by NSTAR (or the Transmission Customer, if so agreed) is found to be inaccurate in excess of two percent (2%), up or down, the owner of the metering equipment shall cause it to be made accurate or replaced and the meter readings and rate computation for the period of inaccuracy shall be adjusted to correct such inaccuracy so far as the same can be reasonably ascertained, but no adjustment prior to the beginning of the next preceding month shall be made except by agreement of the Parties. In addition to an annual routine test, the owner of the metering equipment shall cause such equipment to be tested at any time upon written request of the other Party. If such equipment proves accurate within two percent (2%), up or down, the expense of the test shall be borne by the Party requesting the test. The determination of percent accuracy shall be in accordance with the weighted average percent registration as described in ANSI C12.1-1988, Section 6.1.8.1. The owner of the metering equipment shall comply with any reasonable request of the other Party concerning the sealing of meters, the presence of a representative when the seals are broken and tests are made, and other matters affecting the accuracy of the measurement of electricity hereunder.

10.0 COMPENSATION FOR LOCAL POINT-TO-POINT SERVICE

Rates for Firm and Non-Firm Local Point-To-Point Service shall be determined as set forth in the Schedules appended to this Local Service Schedule: Firm Local Point-To-Point Service (Schedule 3) and Non-Firm Local Point-To-Point Service (Schedule 4). Such rates shall be determined on the basis of estimated costs for each Service Year until the actual costs for such Service Year are determined.

Thereafter, payments made on such estimated costs shall be recalculated based on actual data for that Service Year, and an appropriate billing adjustment shall be made pursuant to Section 4 of this Local Service Schedule.

NSTAR shall use this Local Service Schedule to make its Third-Party Sales to be transmitted as Local Point-To-Point Service. NSTAR shall account for such use at the applicable rates, pursuant to Section II.8.5 of the Tariff.

11.0 STRANDED COST RECOVERY

NSTAR may seek to recover stranded costs from the Transmission Customer pursuant to this Local Service Schedule in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, NSTAR must separately file any specific proposed stranded cost charge under Section 205 of the Federal Power Act.

III LOCAL NETWORK SERVICE

12.0 NATURE OF LOCAL NETWORK SERVICE

12.1 Real Power Losses

Real power losses associated with transactions on Non-PTF shall be determined based on estimated average system losses for metering points on NSTAR's Local Network; the loss factor will be three and one tenth percent (3.1%).

12.2 Metering

Unless agreed otherwise, all meters, including any recording devices or telemetry equipment shall be owned, operated, maintained and tested by NSTAR or its Designated Agent in accordance with ISO Operating Procedures at the Transmission Customer's expense. NSTAR shall provide access to metering data, including telephone line access, which may reasonably be required to facilitate measurement and billing under a Service Agreement at the requesting Party's expense.

NSTAR reserves the sole right to determine appropriate metering installations. When new metering equipment is required, it shall be supplied by NSTAR, at the Transmission Customer's expense, including applicable taxes, and overhead costs, in conformity with ISO Operating

Procedures.

If at any time any metering equipment owned by NSTAR (or Transmission Customer, if so agreed) is found to be inaccurate in excess of two percent (2%), up or down, the owner of the metering equipment shall cause it to be made accurate or replaced and the meter readings and rate computation for the period of inaccuracy shall be adjusted to correct such inaccuracy so far as the same can be reasonably ascertained, but no adjustment prior to the beginning of the next preceding month shall be made except by agreement of the Parties. In addition to an annual routine test, the owner of the metering equipment shall cause such equipment to be tested at any time upon written request of the other Party.

If such equipment proves accurate within two percent (2%), up or down, the expense of the test shall be borne by the Party requesting the test. The determination of percent accuracy shall be in accordance with the weighted average percent registration as described in ANSI C12.1-1988, Section 6.1.8.1. The owner of the metering equipment shall comply with any reasonable request of the other Party concerning the sealing of meters, the presence of a representative when the seals are broken and tests are made, and other matters affecting the accuracy of the measurement of electricity hereunder.

13.0 NETWORK RESOURCES

13.1 Operation of Network Resources

The Network Customer shall not operate its designated Network Resources located in the Network Customer's or NSTAR's Control Area such that the output of those facilities exceeds its designated Local Network Load, plus Non-Firm Sales delivered pursuant to Part II of this Local Service Schedule, plus losses. This limitation shall not apply to changes in the operation of a Transmission Customer's Network Resources at the request of NSTAR to respond to an emergency or other unforeseen condition which may impair or degrade the reliability of the Transmission System.

13.2 Transmission Arrangements for Network Resources Not Physically Interconnected With NSTAR

The Network Customer shall be responsible for any arrangements necessary to deliver capacity and energy from a Network Resource not physically interconnected with NSTAR's Transmission

System. NSTAR will undertake reasonable efforts to assist the Network Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice.

13.3 Use of Interface Capacity by the Network Customer

Unless otherwise provided under the Tariff, there is no limitation upon a Network Customer's use of NSTAR's Transmission System at any particular interface to integrate the Network Customer's Network Resources (or substitute economy purchases) with its Local Network Loads. However, unless otherwise provided by the Tariff, a Network Customer's use of NSTAR's total interface capacity with other transmission systems may not exceed the Network Customer's Load.

13.4 Network Customer Owned Transmission Facilities

The Network Customer that owns existing transmission facilities that are integrated with NSTAR's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration the Network Customer must demonstrate that its transmission facilities are integrated into the plans or operations of NSTAR to serve its power and transmission customers. For facilities constructed by the Network Customer subsequent to the Service Commencement Date under this Local Service Schedule, the Network Customer shall receive credit where such facilities are jointly planned and installed in coordination with NSTAR. Calculation of the credit shall be addressed in either the Network Customer's Service Agreement or any other agreement between the Parties.

14.0 DESIGNATION OF LOCAL NETWORK LOAD

14.1 Local Network Load

The Network Customer must designate the individual Local Network Loads on whose behalf NSTAR will provide Local Network Service. The Local Network Loads shall be specified in the Service Agreement.

14.2 Local Network Load Not Physically Interconnected with NSTAR

This section applies to both initial designation pursuant to Section 15.1 and the subsequent addition of new Local Network Load not physically interconnected with NSTAR. To the extent that the Network Customer desires to obtain transmission service for a load outside NSTAR's Transmission System, the Network Customer shall have the option of (1) electing to include the

entire load as Local Network Load for all purposes under this Local Service Schedule and designating Network Resources in connection with such additional Local Network Load, or (2) excluding that entire load from its Local Network Load and purchasing Local Point-To-Point Service under this Local Service Schedule.

To the extent that the Network Customer gives notice of its intent to add a new Local Network Load as part of its Local Network Load pursuant to this section, the request must be made through a modification of service pursuant to a new Application.

15.0 LOAD SHEDDING AND CURTAILMENTS

15.1 Procedures

Prior to the Service Commencement Date, NSTAR and the Network Customer shall establish Load Shedding and Curtailment procedures pursuant to the OATT with the objective of responding to contingencies on the Transmission System. The Parties will implement such programs during any period when NSTAR, the Local Control Center or ISO, as appropriate, determines that a system contingency exists and such procedures are necessary to alleviate such contingency. NSTAR will notify all affected Network Customers in a timely manner of any scheduled Curtailment.

15.2 Allocation of Curtailments

NSTAR shall, on a non-discriminatory basis, effect a Curtailment of the transaction(s) that effectively relieves the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by NSTAR and Network Customer in proportion to their respective Load Ratio Shares. NSTAR shall not direct the Network Customer to effect a Curtailment of schedules to an extent greater than NSTAR would effect a Curtailment of NSTAR's schedules under similar circumstances.

15.3 Load Shedding

To the extent that a system contingency exists on NSTAR's Transmission System and ISO, the Local Control Center or NSTAR, as appropriate, determines that it is necessary for NSTAR, Local Point-to-Point Customers and Network Customers to shed load, the Parties shall shed load in accordance with the OATT.

15.4 System Reliability

Any Curtailment of Local Network Service will be not unduly discriminatory relative to NSTAR's use of the Transmission System on behalf of its Native Load Customers. In the event that the Network Customer fails to respond to established Load Shedding and Curtailment procedures, NSTAR shall assess a penalty charge. Said penalty charge will be determined in accordance with Section 16.2.

16.0 RATES AND CHARGES

Rates for Local Network Service shall be determined as set forth in this Section 16 on the basis of estimated costs for each Service Year until the actual costs for such Service Year are determined. Thereafter, payments made on such estimated costs shall be recalculated based on actual data for that Service Year, and all appropriate billing adjustments shall be made pursuant to Section 4 of this Local Service Schedule.

The Network Customer shall pay NSTAR for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following:

16.1 Monthly Demand Charge

The Network Customer shall pay a Monthly Demand Charge which shall be the Embedded Cost Charge. The Embedded Cost Charge shall be determined by multiplying the Network Customer's Load Ratio Share by one twelfth (1/12) of NSTAR's Annual Transmission Revenue Requirements, as determined in accordance with Attachment D of this Local Service Schedule and as subject to an Annual True-up pursuant to Section 4. The Embedded Cost Charge is based on NSTAR's system average embedded cost. In the event NSTAR seeks to apply a rate based on a methodology other than average embedded cost to all or any part of a Network Customer's service, either already being provided or proposed to be provided, NSTAR shall provide the affected Network Customer thirty days advance written notice of any filing with the Commission seeking to implement such a rate and shall comply with all applicable requirements of the Commission and the Tariff. Any dispute as to NSTAR's position concerning proposed cost allocation shall be addressed as provided in Section II.7(g) of Schedule 21-Local Service to Section II of the Tariff; provided that nothing in this provision prevents NSTAR from filing with the Commission at any time to establish new rates pursuant to the provisions of Section 205 of the FPA or a Network Customer from opposing such a filing, and nothing in this provision is intended to reflect a Network Customer's agreement that NSTAR has the rights set out in this

Section 16.1 or is intended to prevent the affected Network Customer from filing a complaint with the Commission at any time pursuant to the provisions of Section 206 of the FPA or NSTAR from opposing such a filing.

16.2 Curtailment Penalty Charge

If the Transmission Customer fails to respond to established emergency load shedding and curtailment procedures to relieve emergencies on the transmission system, NSTAR may assess a penalty charge to the Transmission Customer. Said penalty charge will be equal to two (2) times the Monthly Demand Charge for Local Network Service, as calculated in accordance with Section 16.1 of this Local Service Schedule, for the month in which such service was not curtailed or interrupted.

16.3 [Reserved]

16.4 Taxes and Fees Charge

16.4.1 If NSTAR incurs tax liability currently for which it will in subsequent years receive tax benefits (for example, a taxable contribution in aid of construction) then Transmission Customer shall pay to NSTAR an amount sufficient to reimburse NSTAR, on a net present value basis, for the reasonably projected costs resulting from the tax liability incurred in the current year less the reasonably projected tax benefits received by NSTAR in future years. Sections 16.4.1 and 16.4.2 are intended to apply to those Transmission Customers for whom Direct Assignment Facilities are constructed pursuant to this Local Service Schedule and to any Transmission Customer's appropriate share of the cost of any required Local Network Upgrades to the extent that any such Local Network Upgrade is identified pursuant to the study procedures outlined in Schedule 21-Local Service, Section II.7(d) and permitted or required by Commission ruling to be paid as a contribution in aid of construction.

16.4.2 If NSTAR takes a position that any particular transaction under any section of the Local Service Schedule does not constitute a transaction of the type described immediately above, and that position is subsequently reversed by Treasury ruling or regulation or court action, then the Transmission Customer shall pay to NSTAR an amount calculated as described above, but additionally taking into account any interest assessment required

to be paid by NSTAR.

16.4.3 At its effective date, this Section 16.4 applies only to contributions in aid of construction ("CIAC"). NSTAR reserves the right to file under Section 205 of the FPA to modify this provision to apply to items other than CIAC and the Network Customer reserves the right to oppose any such filing.

17.0 OPERATING ARRANGEMENTS

17.1 Operating Requirements

The terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of this Local Service Schedule shall be specified in the OATT. The OATT shall provide for the Parties to:

(i) operate and maintain equipment necessary for integrating the Network Customer within NSTAR's Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment),

(ii) transfer data between NSTAR and the Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside NSTAR's Transmission System, interchange schedules, unit outputs for redispatch required under Section 15, voltage schedules, loss factors and other real time data),

(iii) use software programs required for data links and constraint dispatching,

(iv) exchange data on forecasted loads and resources necessary for long-term planning, and

(v) address any other technical and operational considerations required for implementation of this Local Service Schedule, including scheduling protocols.

The OATT will recognize that the Network Customer shall either:

(i) operate as a Control Area under applicable guidelines of the Electric Reliability Organization (ERO), as defined in 18 CFR 38.1, and ISO,

(ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with NSTAR, or

(iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies the applicable reliability guidelines of the ERO and ISO. NSTAR shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services.

17.2 <u>Network Operating Committee</u>

A Network Operating Committee (Committee) shall be established to coordinate operating criteria for the Parties' respective responsibilities under the OATT. Each Network Customer shall be entitled to have at least one representative on the Committee. The Committee shall meet from time to time as need requires, but no less than once each calendar year.

SCHEDULE 2

SUPPLEMENTAL END-USE REACTIVE SUPPORT SERVICE

In the event that power factor levels and reactive supply requirements set forth in the service agreement or other associated operating or interconnect agreement are not maintained by the Delivering Party (or, as appropriate, the Receiving Party), in accordance with applicable ISO standards and practices then NSTAR shall charge the Transmission Customer to take corrective action. The Transmission customer shall compensate NSTAR for installing the necessary equipment, whether in the form of generating units or other non-generating resources, such as demand resources, to correct the incremental difference between the Transmission Customer's lowest (or highest) power factor level and that which is an acceptable level in accordance with ISO standards and practices. The charges will be based upon the necessary level of reactive power supply required to correct the deficiency in the power factor level.

For the KVAR demand supplied to the Transmission Customer, the charge shall be the greater of a) the market price of installing leading reactive power supply expressed in terms of $/KVAR or b) $50/KVAR of installed (leading) reactive power reflecting current NSTAR cost.

For the KVAR demand absorbed by NSTAR the charge shall be the greater of a) the market price of installing lagging reactive power supply expressed in terms of $/KVAR or b) $22.5/KVAR of installed (lagging) reactive power reflecting current NSTAR cost.

SCHEDULE 3

LONG-TERM FIRM AND SHORT-TERM FIRM

LOCAL POINT-TO-POINT SERVICE

The Transmission Customer shall compensate NSTAR for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following charges as applicable:

1) Annual Rate

The Annual Rate for Firm Local Point-To-Point Service shall consist of the higher of (i) the Embedded Cost Charge or (ii) the Incremental Cost Charge, as set forth below:

(i) The Embedded Cost Charge shall be determined by dividing NSTAR's Annual Transmission Revenue Requirements (determined in accordance with Attachment D of this Local Service Schedule) by the maximum amount of NSTAR's Monthly Transmission System Load during such Service Year.

(ii) The Incremental Cost Charge shall be determined from the total costs of all Local Network Upgrades plus other incremental costs incurred provided for in the Service Agreement application to a transaction. If the Incremental Cost Charge is higher, the Transmission Customer shall pay for the facilities necessary to provide it with service during an amortization period, with the Transmission Customer paying the Embedded Cost Charge upon completion of the amortization. Such amortization period shall be coterminous with the Service Agreement.

2) Firm Local Point-To-Point Service for Monthly Transactions or Longer Term Transactions

The charge for each month applicable to a monthly transaction or longer term transaction (the "Monthly Rate") shall be determined as the product of: (a) NSTAR's Annual Rate for Firm Local Point-To-Point Service divided by twelve (12) months and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Service Agreement for such month, expressed in kilowatts.

3) Firm Local Point-To-Point Service for Less Than One Month

NSTAR's Weekly Rate is equal to NSTAR's Annual Rate for Firm Local Point-To-Point Service divided by fifty-two (52) weeks. NSTAR's Daily Rate is equal to NSTAR's Annual Rate for Firm Local Point-To-Point Service divided by three hundred and sixty-five (365) days. NSTAR's Hourly Rate is equal to

NSTAR’s Annual Rate for Firm Local Point-To-Point Service divided by eight thousand seven hundred and sixty (8,760) hours.

The Transmission Customer shall pay the Weekly, Daily or Hourly Rate, as applicable, times the Reserved Capacity set forth in the Transmission Customer’s Applicable Service Agreement.

4) Penalty

When the Transmission Customer exceeds its Reserved Capacity or uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved (Excess Incident), NSTAR will charge the Transmission Customer 200% of the rate determined as follows for each kilowatt of the Excess Incident:

- The unreserved use penalty for a single hour of unreserved use shall be based on the rate for daily Firm Point-to Point Transmission Service.

- If there is more than one assessment for a given duration (e.g., daily) for the Transmission Customer, the penalty shall be based on the next longest duration (e.g., weekly).

- The unreserved penalty charge for multiple instances of unreserved use (i.e., more than one hour) within a day shall be based on the daily rate for Firm Point-To-Point Transmission Service.

- The unreserved penalty charge for multiple instances of unreserved use isolated to one calendar week shall be based on the charge for weekly Firm Point-To-Point Transmission Service.

- The unreserved use penalty charge for multiple instances of unreserved use during more than one week during a calendar month shall be based on the charge for monthly Firm Point-To-Point Transmission Service.

- The unreserved use penalty charge for multiple instances of unreserved use during more than one month during a calendar year shall be based on the charge for yearly Firm Point-To-Point Transmission Service.

All Excess Incidents will be recorded by NSTAR, and if in any calendar year more than ten (10) Excess Incidents occur in connection with service for the Transmission Customer, then NSTAR may require the Transmission Customer to apply for additional Firm Local Point-To-Point Service under this Local

Service Schedule in the amount equal to the highest Excess Incident during that Service Year. Charges for such additional transmission service will relate back to the first day of the month following the month of NSTAR's notice.

5) Curtailment Penalty Charge

If the Transmission Customer fails to respond to established emergency load shedding and curtailment procedures to relieve emergencies on the Transmission System, NSTAR may assess a penalty charge to the Transmission Customer. Said penalty charge will be equal to two (2) times the Monthly Rate for Firm Local Point-To-Point Service for the month in which such service was not curtailed or interrupted.

6) Taxes and Fees Charge

A) If any governmental authority requires the payment of any fee or assessment not specifically provided for in any of the charge or rate provisions under this Local Service Schedule or imposes a sales, gross revenue, or other form of tax with respect to payments made for service provided under this Local Service Schedule, including any applicable interest charged on any deficiency assessment made by the taxing authority, together with any further tax on such payments, the obligation to make payment for any such fee, assessment, or tax shall be borne by the Transmission Customer. NSTAR will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's Regulations.

B) If NSTAR incurs tax liability currently for which it will, in subsequent years, receive tax benefits (for example, a taxable contribution in aid of construction), the Transmission Customer shall pay to NSTAR an amount sufficient to reimburse NSTAR, on a net present value basis, for the reasonably projected costs resulting from the tax liability incurred in the current year less the reasonably projected tax benefits received by NSTAR in future years.

C) If NSTAR takes a position that any particular transaction under any section of this Local Service Schedule does not constitute a transaction of the type described immediately above, and that position is subsequently reversed by Treasury ruling or regulation, or court action, then the Transmission Customer shall pay to NSTAR an amount calculated as described above but additionally taking into account any interest assessment required to be paid by NSTAR.

7) Regulatory Expense Charge

NSTAR shall have the right to make a Section 205 filing for recovery of regulatory expenses associated with this Local Service Schedule and the Service Agreement(s).

8) Customer-Related Expense Charge

NSTAR shall charge the Transmission Customer, in addition to the other charges assessed pursuant to this Local Service Schedule, and as set forth in its Service Agreement for those costs attributable to the billing, meter reading, record keeping, (all from FERC Uniform System of Accounts Nos. 901-905) and an allocation of administrative and general expenses (FERC Uniform System of Accounts Nos. 920-935) associated with each of these costs, all of which are related to the Transmission Customer's Local Point-To-Point Service and allocated on the basis of the total number of customers served by NSTAR.

9) Exchanges

With respect to any transactions that involve an exchange, each party to such transaction shall be an individual Transmission Customer under this Local Service Schedule. Accordingly, a transmission charge, as applicable, will be calculated for, and a separate bill will be rendered to, each such Transmission Customer.

10) Discounts

Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by NSTAR must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, NSTAR must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

11) Resales

The rates and rules governing charges and discounts shall not apply to resales of transmission service, compensation for which shall be governed by § I.11(a) of Schedule 21.

SCHEDULE 4

NON-FIRM LOCAL POINT-TO-POINT SERVICE

The Transmission Customer shall compensate NSTAR for any Ancillary Services and for Non-Firm Local Point-To-Point Service up to the sum of the applicable charges set forth below:

1) The Annual Rate for Non-Firm Local Point-To-Point Service shall be NSTAR's Annual Transmission Revenue Requirements (determined in accordance with Attachment D of this Local Service Schedule) for the Service Year divided by NSTAR's Monthly Transmission System Load during such Service Year.

2) Non-Firm Local Point-To-Point Service for Monthly Transactions or Longer Term Transactions
The charge for each month applicable to a monthly transaction or longer term transaction (the "Monthly Rate") shall be determined as the product of: (a) NSTAR's Annual Rate for Non-Firm Local Point-To-Point Service divided by twelve (12) months and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Service Agreement for such month, expressed in kilowatts.

3) Non-Firm Local Point-To-Point Service for Less Than One Month
NSTAR's Weekly Rate is equal to NSTAR's Annual Rate for Non-Firm Local Point-To-Point Service divided by fifty-two (52) weeks.

NSTAR's Daily Rate is equal to NSTAR's Annual Rate for Non-Firm Local Point-To-Point Service divided by three hundred and sixty-five (365) days. NSTAR's Hourly Rate is equal to NSTAR's Annual Rate for Non-Firm Local Point-To-Point Service divided by eight thousand seven hundred and sixty (8,760) hours.

The Transmission Customer shall pay the Weekly, Daily or Hourly Rate, as applicable, time the Reserved Capacity set forth in the Transmission Customer's Applicable Service Agreement.

4) Credit to the Transmission Charge
Whenever service provided hereunder is interrupted or curtailed by NSTAR, or its Designated Agent including ISO, the Transmission Charges to the Transmission Customer calculated pursuant to Sections 2 and 3 of this Schedule 4 shall be credited by an amount equal to the sum of the credits calculated for each hour of interruption or curtailment in service. The credit to the Transmission Customer for each hour of

interruption or curtailment shall be calculated as the product of (a) NSTAR's Hourly Rate and (b) the kilowatts of service interruption or curtailment during such hour.

5) <u>Penalty</u>

When the Transmission Customer exceeds its Reserved Capacity or uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved (Excess Incident), NSTAR will charge the Transmission Customer 200% of the rate determined as follows for each kilowatt of the Excess Incident:

- The unreserved use penalty for a single hour of unreserved use shall be based on the rate for daily Firm Point-to Point Transmission Service.

- If there is more than one assessment for a given duration (e.g., daily) for the Transmission Customer, the penalty shall be based on the next longest duration (e.g., weekly).

- The unreserved penalty charge for multiple instances of unreserved use (i.e., more than one hour) within a day shall be based on the daily rate for Firm Point-To-Point Transmission Service.

- The unreserved penalty charge for multiple instances of unreserved use isolated to one calendar week shall be based on the charge for weekly Firm Point-To-Point Transmission Service.

- The unreserved use penalty charge for multiple instances of unreserved use during more than one week during a calendar month shall be based on the charge for monthly Firm Point-To-Point Transmission Service.

- The unreserved use penalty charge for multiple instances of unreserved use during more than one month during a calendar year shall be based on the charge for yearly Firm Point-To-Point Transmission Service.

All Excess Incidents will be recorded by NSTAR, and if in any calendar year more than ten (10) Excess Incidents occur in connection with service for the Transmission Customer, then NSTAR may require the Transmission Customer to apply for additional Non-Firm Local Point-To-Point Service under this Local Service Schedule in the amount equal to the highest Excess Incident during that Service Year. Charges for such additional Non-Firm Local Point-To-Point Service will relate back to the first day of the month following the month of NSTAR's notice.

6) Curtailment Penalty Charge.

If the Transmission Customer fails to respond to established emergency load shedding and curtailment procedures to relieve emergencies on the Transmission System, NSTAR may assess a penalty charge to the Transmission Customer. Said penalty charge will be equal to two (2) times the monthly demand charge for Non-Firm Local Point-To-Point Service for the month in which such service was not curtailed or interrupted.

7) Taxes and Fees Charge

A) If any governmental authority requires the payment of any fee or assessment not specifically provided for in any of the charge or rate provisions under this Local Service Schedule or imposes a sales, gross revenue, or other form of tax with respect to payments made for service provided under this Local Service Schedule, including any applicable interest charged on any deficiency assessment made by the taxing authority, together with any further tax on such payments, the obligation to make payment for any such fee, assessment, or tax shall be borne by the Transmission Customer. NSTAR will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's Regulations.

B) If NSTAR incurs tax liability currently for which it will, in subsequent years, receive tax benefits (for example, a taxable contribution in aid of construction), the Transmission Customer shall pay to NSTAR an amount sufficient to reimburse NSTAR, on a net present value basis, for the reasonably projected costs resulting from the tax liability incurred in the current year less the reasonably projected tax benefits received by NSTAR in future years.

C) If NSTAR takes a position that any particular transaction under any section of this Local Service Schedule does not constitute a transaction of the type described immediately above, and that position is subsequently reversed by Treasury ruling or regulation, or court action, then the Transmission Customer shall pay to NSTAR an amount calculated as described above but additionally taking into account any interest assessment required to be paid by NSTAR.

8) Regulatory Expense Charge

NSTAR shall have the right to make a Section 205 filing for recovery of regulatory expenses associated with this Local Service Schedule and the Service Agreement(s).

9) Customer-Related Transaction Charge

NSTAR shall charge the Transmission Customer, in addition to the other charges assessed pursuant to this Local Service Schedule, and as set forth in its Service Agreement for those costs attributable to the billing, meter reading, record keeping, (from FERC Uniform System of Accounts Nos. 901-905) and an allocation of administrative and general expenses (Nos. 920-935) associated with each of these costs, all of which are related to the Transmission Customer's Local Point-To-Point Service and allocated on the basis of the total number of customers served by NSTAR.

10) Exchanges

With respect to any transactions that involve an exchange, each party to such transaction shall be an individual Transmission Customer under this Local Service Schedule. Accordingly, a transmission charge, as applicable, will be calculated for, and a separate bill will be rendered to, each such Transmission Customer.

11) Discounts

Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by NSTAR must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, NSTAR must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

12) Resales

The rates and rules governing charges and discounts shall not apply to resales of transmission service, compensation for which shall be governed by § I.11(a) of Schedule 21.

ATTACHMENT A

METHODOLOGY TO ASSESS AVAILABLE TRANSFER CAPABILITY

1. Introduction

ISO is the regional transmission organization ("RTO"), serving the New England Control Area. ISO is responsible for development, oversight, and fair administration of New England's wholesale market and management of bulk electric power system and wholesale markets' planning processes. The ISO serves as the Balancing Authority for the New England Control Area. The New England Control Area is interconnected to three neighboring Balancing Authority Areas: New Brunswick System Operator Area ("NBSO Area"), New York Independent System Operator Area ("NYISO Area"), and Hydro-Québec TransÉnergie Area ("HQTÉ Area").

As part of its RTO responsibilities, the ISO is registered with the North American Electric Reliability Corporation ("NERC") as several functional model entities that have responsibilities related to the calculation of ATC as defined in the following NERC Standards: MOD-001 – Available Transmission System Capability ("MOD-001"), MOD-004 – Capacity Benefit Margin ("MOD-004"), and MOD-008 – Transmission Reliability Margin Calculation Methodology ("MOD-008"). The extent of those responsibilities is based on various Commission-approved transmission operating agreements and the provisions of the ISO New England Operating Documents.

While the ISO is the transmission provider for transmission service associated with PTF, the Participating Transmission Owners (PTOs) under the Transmission Operating Agreement, such as NSTAR, provide local transmission service over Non-Pool Transmission Facilities within the RTO footprint and are responsible for calculating TTC and ATC associated with Local Service provided under Schedule 21. Pursuant to CFR § 37.6(b)[1]of the Commission's regulations, NSTAR as a Transmission Provider is obligated to calculate and post ATC and TTC for certain local facilities over which Point-to-Point transmission service is provided under Schedule 21-NSTAR. These are primarily radial paths that provide transmission service to directly interconnected generators.

[1]§37.6(b) Posting transfer capability. The available transfer capability (ATC) on the Transmission Provider's system and the total transfer capability (TTC) of that system shall be calculated and posted for each Posted Path as set forth in this section.

Posted Path is defined as any control area-to-control area interconnection; any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a

customer requests to have ATC or TTC posted. For this last category, the posting must continue for 180 days and thereafter until 180 days have elapsed from the most recent request for service over the requested path. For purposes of this definition, an hour includes any part of any hour during which serviced was denied, curtailed or interrupted. §37.6(b)(1)(i).

NSTAR does not currently have any Posted Paths based on the above definition. However, to the extent that NSTAR does in the future have any Posted Path(s), NSTAR will calculate ATC and TTC using NERC Standard MOD-029-1 Rated System Path Methodology as outlined below.

1.1 Scope of Document

The scope of this document is limited to the following functions which are performed or utilized by NSTAR in order to provide Local Point-to Point Service under Schedule 21-NSTAR: Total Transfer Capability (TTC) methodology; Available Transfer Capability (ATC) methodology; Existing Transmission Commitment (ETC); Use of Transmission Reliability Margin (TRM); Use of Capacity Benefit Margin (CBM); and Use of Rollover Rights (ROR) in the calculation of ETC.

TTC and ATC are required to be calculated only for certain non-PTF internal paths over which Local Point-to-Point Service is provided under Schedule 21-NSTAR. TTC and ATC are not calculated by NSTAR for Local Network Service because ISO employs a market model for economic, security constrained dispatch of generation, and NSTAR does not require advance reservation for such network service.

2. Transmission Service in the New England Markets

Since the inception of the open access transmission tariff for New England, the process by which generation located inside New England supplies energy and/or capacity to the bulk electric system has differed from the Commission’s pro forma open access transmission tariff. The fundamental difference is that internal generation is dispatched in an economic, security constrained manner by the ISO rather than utilizing a system of physical rights, advance reservations and point-to-point transmission service. Through this process, internal generation provides offers that are utilized by the ISO in the Real-Time Energy Market dispatch software. This process provides the least-cost dispatch to satisfy Real-Time load on the system.

In addition to offers from generation within New England, entities may submit energy transactions that move into the New England Control Area, out of the New England Control Area or through the New

England Control Area. The Real-Time Energy Market clears these External Transactions based on forecast LMPs and the transfer capability of the associated external interfaces. With those External Transactions in place, the Real-Time Energy Market dispatches internal generation in an economic, security constrained manner to meet Real-Time load within the region.

The process for submitting External Transactions into the Real-Time Energy Market does not require an advance physical reservation for use of the PTF. In the event that the net of economic External Transactions is greater than the transfer capability of the associated external interface, the ExternalTransactions selected to flow are selected based on the rules specified in the Tariff. For any External Transactions that are confirmed to flow in Real-Time based on the economics of the system, a transmission reservation for RNS and Through-or-Out Service is created after-the-fact to satisfy the transparency needs of the market.

The process described above is applicable to the PTF within the New England Control Area, and non-PTF where utilized for Local Network Service by generation or load. However, NSTAR owns local transmission facilities over which an advance transmission service reservation for firm or non-firm transmission service may be required. On those facilities, Market Participants may obtain a transmission service reservation from NSTAR under Schedule 21-NSTAR prior to delivery of energy and/or capacity into the New England markets pursuant to Schedule 18, 20A or 20B of the Tariff. This document addresses the calculation of ATC and TTC for these non-PTF internal paths.

3. <u>NSTAR Total Transfer Capability (TTC)</u>

TTC is the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions. TTC for Schedule 21-NSTAR is calculated using NERC Standard MOD-029-1 Rated System Path Methodology and posted on the NSTAR OASIS site.

The TTC on NSTAR’s Non-PTF that requires Local Point-to-Point Service reservations are relatively static values. NSTAR calculates the TTC for Posted Paths as the rating of the particular radial transmission path.NSTAR will calculate and post TTC on its OASIS site for all non-PTF Posted Paths that are eligible for Local Point-to-Point Service reservations. TTC is calculated as the transfer capability rating of the particular radial transmission path less the most limiting element within the PostedPath.

4. <u>Capacity Benefit Margin (CBM)</u>

CBM is defined as the amount of firm transmission transfer capability set aside by a Transmission Provider for use by the Load Serving Entities. The ISO does not set aside any CBM for use by the Load Serving Entities, because of the New England approach to capacity planning requirements in the ISO New England Operating Documents, and in any event, ISO's determination of CBM does not apply directly to the determination of ATC for Local Service. Load Serving Entities operating with the New England Control Area are required to arrange for their Capacity Requirements prior to the beginning of any given month in accordance with the Tariff, Section III.13.7.3.1 (Calculation of Capacity Requirement and Capacity Load Obligation). Load Serving Entities do not utilize CBM to ensure that their capacity needs are met; therefore, CBM is not applicable within the New England market design. Accordingly, for purposes of NSTAR's ATC calculation and because CBM for the New England Control Area is set to zero (0), NSTAR utilizes a zero (0) CBM value.

5. Transmission Reliability Margin (TRM)

TRM is the amount of transmission transfer capability set aside to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. It is used only for external interfaces under the New England market design. As NSTAR does not have any external interfaces, TRM for its non-PTF facilities is presently set to zero.

6. Existing Transmission Commitments

6.1 Existing Transmission Commitments, Firm (ETC_F)

ETC_F are confirmed Firm Local Point-To-Point Transmission Service reservations (PTP_F) plus any exercised rollover rights for Firm Point-To-Point Transmission Service reservations (ROR_F). There are no allowances necessary for Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$), grandfathered Transmission Service (GF_F), and other services, contracts or agreements (OS_F) to be considered in the ETC_Fcalculation.

6.2 Existing Transmission Commitments, Non-Firm (ETC_{NF})

ETC_{NF} are confirmed Non-Firm transmission reservations (PTP_{NF}). There are no allowances necessary for Non-Firm Network Integration Transmission Service ($NITS_{NF}$), Non-Firm grandfathered Transmission Service (GF_{NF}), or other services, contracts or agreements (OS_{NF}).

7. Calculation of ATC for NSTAR's Transmission System

NERC Standards MOD-001-1 – Available Transmission System Capability and MOD-029-1 – Rated

System Path Methodology define the required items to be identified when describing a Transmission Provider's ATC methodology. As a practical matter, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

Common practice is not to calculate or post firm and non-firm ATC values for the Non-PTF assets, as ATC is positive and listed as 9999. Transmission Customers are not restricted from reserving Firm or Non-Firm Point-to-Point Service on Non-PTF facilities.

As Real-Time approaches, the ISO utilizes the Real-Time Energy Market rules to determine which of the submitted energy transactions will be scheduled in the coming hour. Basically, the ATC of the non-PTF assets in the New England market is almost always positive. The ATC is equal to the amount of net energy and/or capacity transactions that the ISO will schedule on an interface for the designated hour. With this simplified version of ATC, there is no detailed algorithm to be described or posted other than: ATC equals TTC. Thus, for those non-PTF that serve as a path for NSTAR's Transmission Customers taking Local Point-to-Point Service, NSTAR has posted the ATC as 9999, consistent with industry practice. ATC on these paths varies depending on the time of day. However, it is posted with an ATC of "9999" to reflect the fact that there are no restrictions on these paths for commercial transactions.

7.1 Calculation of Schedule 21-NSTAR Firm ATC (ATC_F)

7.1.1 Calculation of ATC_F in the Planning Horizon (PH)

For purposes of this Attachment A, PH is any period before the Operating Horizon.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for TRM, CBM, ETC_F, $Postbacks_F$ and $counterflows_F$. As discussed above, TRM and CBM are zero. Firm Transmission Service under Schedule 21-NSTAR that is available in the PH includes: Yearly, Monthly, Weekly and Daily. $Postbacks_F$ and $counterflows_F$ of Schedule 21-NSTAR transmission reservations are not considered in the ATC calculation. Therefore, ATC_F in the PH is equal to the TTC minus ETC_F.

7.1.2 Calculation of ATC_F in the Operating Horizon (OH)

For purposes of this Attachment A, OH begins noon eastern prevailing time each day. At that time, the OH spans from noon through midnight of the next day for a total of 36 hours. As time progresses, the total hours remaining in the OH decrease until noon the following day when the OH is once again reset to

36 hours.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for ETC_F, CBM, TRM, $Postbacks_F$ and $counterflows_F$. As discussed above, TRM and CBM are zero. Daily Firm Transmission Service under Schedule 21-NSTAR is the only firm service offered in the OH. $Postbacks_F$ and $counterflows_F$ of Schedule 21-NSTAR transmission reservations are not considered in the ATC_F calculation. Therefore, ATC_F in the OH is equal to the TTC minus ETC_F.

7.1.3 Calculation of ATC_F in the Scheduling Horizon (SH)

Because Firm Schedule 21-NSTAR transmission service is not offered in the SH, ATC_F in the SH is zero.

7.2 Calculation of Schedule 21-NSTAR Non-Firm ATC (ATC_{NF})

7.2.1 Calculation of ATC_{NF} in the PH

ATC_{NF} is the capability for Non-Firm transmission reservations that remain after allowing for ETC_F, ETC_{NF}, scheduled CBM (CBM_S), unreleased TRM (TRM_U), Non-Firm Postbacks ($Postbacks_{NF}$) and Non-Firm counterflows ($counterflows_{NF}$). As discussed above, the TRM and CBM for Schedule 21-NSTAR are zero. ATC_{NF} available in the PH includes: Monthly, Weekly, Daily and Hourly. TRM_U, $Postbacks_{NF}$ and $counterflows_{NF}$ of Schedule 21-NSTAR transmission reservations are not considered in this calculation. Therefore, ATC_{NF} in the PH is equal to the TTC minus ETC_F and ETC_{NF}.

7.2.2 Calculation of ATC_{NF} in the OH

ATC_{NF} available in the OH includes: Daily and Hourly. As discussed above, the TRM and CBM for Schedule 21-NSTAR are zero. TRM_U, $counterflows_{NF}$ and ETC_{NF} of Schedule 21-NSTAR transmission reservations are not considered in this calculation. Therefore, ATC_{NF} in the OH is equal to the TTC minus ETC_F plus postbacks of PTP_F in the OH as PTP_{NF} ($Postbacks_{NF}$).

7.3 Negative ATC

As stated above, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available. As also stated above, NSTAR's Non-PTF are primarily radial paths that provide transmission service to directly interconnected generators. It is possible that in the future a particular radial path may interconnect more nameplate capacity generation than the path's TTC. For the local facilities modeled by ISO, and consistent with ISO's economic, security-constrained dispatch methodology, the ISO will only dispatch an amount of generation

interconnected to such path so as not to incur a reliability or stability violation on the subject path. Therefore, ATC in the PH, OH and SH could become zero, but will never be negative.

8. Posting of Schedule 21-NSTAR ATC

8.1 Location of ATC Posting

ATC values are posted on the NSTAR OASIS site.

8.2 Updates to ATC

When any of the variables in the ATC equations change, the ATC values are recalculated and immediately posted.

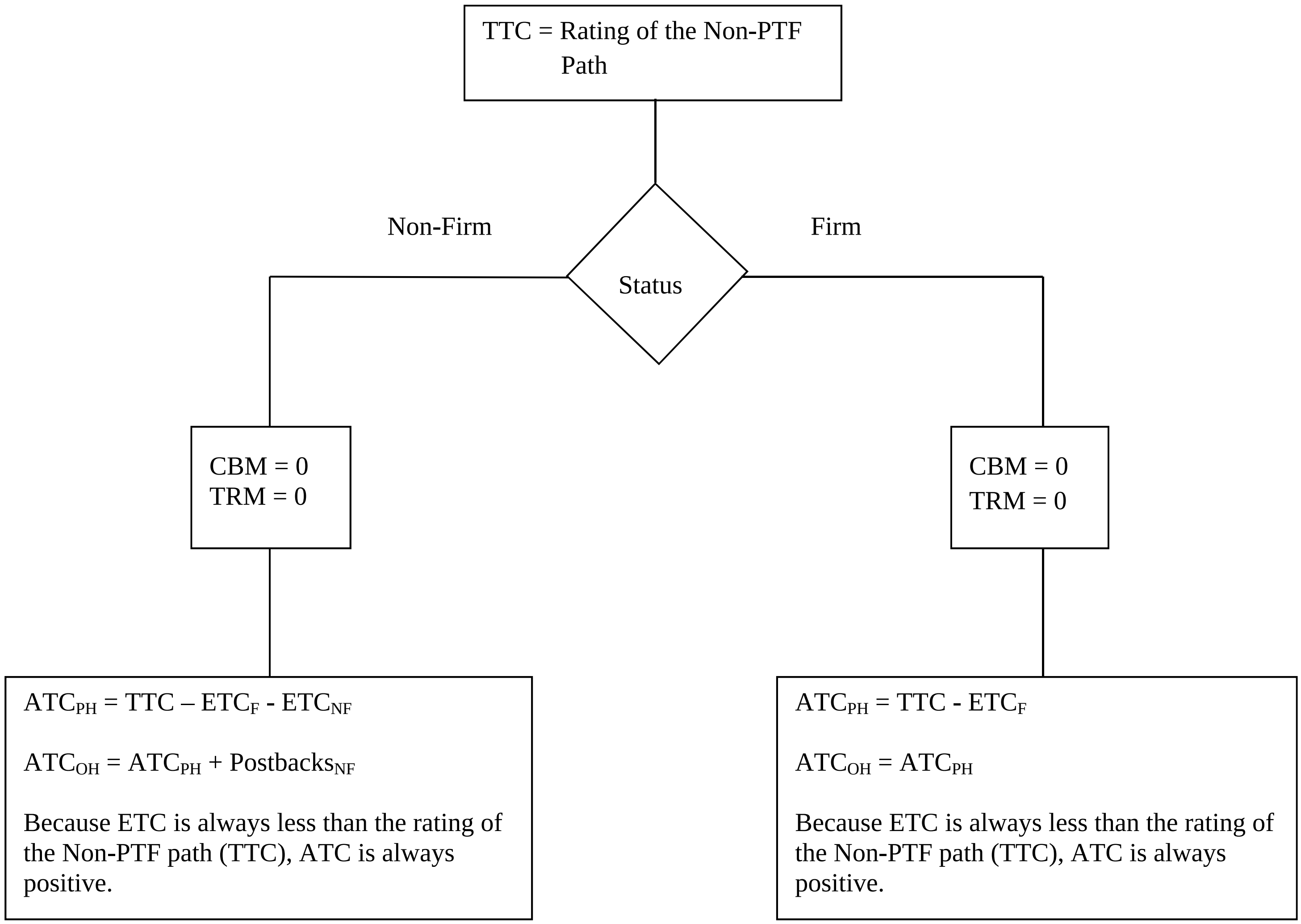
8.3 Coordination of ATC Calculations

NSTAR's Non-PTF has no external interfaces. Therefore, it is not necessary to coordinate the values.

8.4 Mathematical Algorithms

The mathematical algorithms for the calculation of ATC can be found on NSTAR's web site at http://www.nstar.com/business/rates_tariffs/open_access/docs/ATC_Algorithm-Sch_21.pdf

Non-PTF Transmission Path ATC Process Flow Diagram



ATTACHMENT B

METHODOLOGY FOR COMPLETING A SYSTEM IMPACT STUDY

When NSTAR determines on a non-discriminatory basis that a System Impact Study is needed because its Transmission System will be inadequate to accommodate a Completed Application for service, the following outlines the study methodology that NSTAR will employ to estimate the Transmission System impact of a Completed Application for Firm Local Point-To-Point Service, Network Integration Service and/or any costs associated with Direct Assignment Facilities and/or Local Network Upgrades that would be incurred in order to accommodate the service requested in the Completed Application.

1. System Impact will be estimated based on consideration of reliability requirements to:

- meet obligations under agreements that predate this Local Service Schedule;
- meet obligations of existing and pending Completed Application under this Local Service Schedule;
- maintain thermal, voltage and stability system performance within acceptable regional practices.

2. Guidelines and Principles followed by NSTAR: When performing the System Impact Study, NSTAR will apply the following, as amended and/or adopted from time to time.

- Good Utility Practice;
- Criteria, rules and reliability standards applicable to the New England Transmission System;
- NPCC criteria and guidelines; and
- NSTAR criteria and guidelines.

3. Transmission System Model Representation: The Transmission System model will be based on a library of load flow cases prepared by ISO for studies of the New England area. The models may include representations of other NPCC and neighboring systems. These load flow cases include individual system model representations provided by Transmission Owners and represent forecasted system conditions for up to ten (10) years into the future. This library of load flow cases is maintained and updated as appropriate by ISO, and is consistent with information filed under FERC Form 715. NSTAR will use system models that it deems appropriate for study of the Completed Application for service. Additional system models and operating conditions, including assumptions specific to a particular analysis, may be developed for conditions not available in the library of load flow cases. The system models may be modified, if necessary, to include additional system information on load, transfers and

configuration, as it becomes available.

4. System Conditions: Loading of all Transmission System elements shall be less than normal ratings for pre-contingency conditions and less than long-term emergency (LTE) ratings for post-contingency conditions. Post-contingency loading above LTE rating and less than short-term emergency (STE) rating may be allowed where demonstrated that loading can be reduced below the LTE rating within fifteen (15) minutes. Transmission System voltage shall be within the applicable design ratings of connected equipment for normal and emergency conditions. Normal and post-contingency voltages shall be in accordance with NSTAR and ISO standards.

5. Short Circuits: Transmission System short circuit currents shall be within the applicable equipment design ratings.

6. Study Analysis: System impact of the integration of new load will be evaluated to meet the requirements of design, identified in the guidelines and principles under Item 2 above, to provide sufficient transmission capability to maintain stability and to maintain thermal and voltage levels of lines and equipment within applicable limits. The same applies to the evaluation of Firm Point-To-Point Service when it has been determined that insufficient transfer capability is available and the Eligible Customer requests a System Impact Study be conducted.

7. Loss Evaluation: The impact of losses on the Transmission System will be taken into account in the System Impact Study to ensure Good Utility Practice in the design and operation of its system.

8. System Protection: Protection requirements will be evaluated by NSTAR in accordance with ISO, NPCC, and NSTAR criteria.

9. Approvals: NSTAR will conduct the System Impact Study to ensure compliance with its planning and design policies and practices. However, the actions to be taken by the Parties to implement the recommendations of the System Impact Study are subject to approval under the Tariff.

10. Study Scope and Reporting: The study will determine the impacts and identify changes required, if any, to NSTAR's existing Transmission System. NSTAR will provide the Eligible Customer with a written report of the physical interconnection alternative(s), required NSTAR system additions and/or modifications, if any, associated study grade cost estimates (+/- 25%) and the results of the analysis.

ATTACHMENT C

INDEX OF LOCAL POINT-TO-POINT SERVICE CUSTOMERS

Customer	Date of Service Agreement
AIG Trading Corporation	October 29, 1996
Altresco Pittsfield Light Plant	December 26, 1996
Aquila Power Company	February 26, 1997
Axia Energy, LP	June 20, 2001
Baltimore Gas & Electric Co.	January 14, 1997
Bangor Hydro-Electric Co.	October 1, 1996
Belmont Municipal Light Dept.	December 11, 1996
Central Vermont Public Service	January 3, 1997
Chicopee Municipal Light Dept.	October 2, 1996
CINERGY Capital and Trading, Inc.	January 1, 1998
CINERGY Operating Companies	December 1, 1997
Citizens Lehman Power Sales	November 6, 1996
Constellation Power Source, Inc.	July 11, 1997
Duke Energy Solutions, Inc.	March 19, 1999
DukeSolutions, Inc.	May 18, 1999
Edison Source	June 9, 1997
Electric Clearinghouse, Inc.	October 7, 1996
Entergy Nuclear Generation Company	April 10, 2003
Equitable Power Services Company	October 29, 1996
Green Mountain Power Corporation	January 10, 1997
HQ Energy Services (US) Inc.	February 8, 1999
LG&E Power Marketing, Inc.	October 8, 1996
Maine Public Service Company	September 30, 1996
Massachusetts Bay Transportation Authority	May 1, 1999
Massachusetts Municipal Wholesale Electric Co.	September 6, 1996
Merchant Energy Group of the Americas, Inc.	August 16, 1998
Mirant Canal, LLC	July 6, 1998
Mirant Americas Energy Marketing, LP	April 28, 2004
Montaup Electric Co.	October 15, 1996

Morgan Stanley Capital Group, Inc.	October 29, 1996
NEPOOL on Behalf of NEPOOL Participants	June 1, 1997
New England Power Company	December 30, 1996
New York State Gas & Electric Corp.	December 16, 1997
NorAm Energy Services	November 14, 1997
Northeast Energy Services, Inc.	June 17, 1997
NP Energy, Inc.	August 1, 1997
NRG Power Marketing, Inc.	January 1, 2001
NSTAR Electric Company	December 24, 1996
PECO Energy Power Team	January 3, 1997
Rainbow Energy Power Marketing	November 7, 1996
Reading Municipal Light Department	September 6, 1996
Sithe New England Holdings, LLC	January 3, 1998
Sonat Power Marketing, Inc.	November 14, 1997
Southern Energy Trading and Marketing, Inc.	March 10, 1997
Strategic Energy Ltd.	May 11, 1999
The Power Company of America	November 18, 1996
Town of Braintree Electric Light Dept.	September 6, 1996
Town of Hingham Municipal Light Plant	September 9, 1996
Town of Hull Municipal Light Plant	December 11, 1996
Trans Alta Energy Marketing	November 24, 1998
Trans Canada Power Corporation	January 27, 1997
Western Power Services, Inc.	December 24, 1996
Williams Energy Services Company	July 17, 1997
VTEC Energy, Inc.	March 24, 1998

ATTACHMENT D

ANNUAL TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirements for NSTAR ("the Company") will reflect the costs for its Transmission System, including costs attributable to those incurred by the Company in owning, leasing, maintaining and supporting the Transmission System net of revenues for transmission services provided under any other FERC accepted tariff or under any contract with other parties that provides reimbursement to the Company for transmission related services. Under no circumstances shall the Company's Local Network Service rates include costs that are charged through any other rate or tariff. The Transmission Revenue Requirements will be an annual calculation based on the estimated costs for its Transmission System during the Service Year.

The Company shall make an annual informational filing with the FERC on or before May 31 of each year which shall include a True-up of estimated costs and revenues, and actual costs and revenues for the preceding Service Year. Actual costs will be determined using data required to be reported annually in the FERC Form 1 and recorded on the Company's books in accordance with FERC's Uniform System of Accounts; unless the use of other data, such as subaccount balances, is specifically required by the provisions below, in which case an officer of the Company, shall certify that the development, accuracy and application of such other data is in accordance with the provisions of this Local Service Schedule. Such certification will be included with the annual informational filing along with adequate detail that supports the values contained within the True-up calculation. References to specific FERC Form 1 pages, line numbers and columns included in this Local Service Schedule are based on the 2006 Form 1 of the Company's predecessor entities. Subsequent FERC changes to Form 1 may be adopted to the extent they are consistent with the provisions and terms of this Local Service Schedule and not otherwise prohibited by FERC.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section II.1 of the OATT or the Local Service Schedule and as used herein have the following definitions:

A. ALLOCATION FACTORS

1. Transmission Wages and Salaries Allocation Factor shall equal the ratio of transmission-related direct wages and salaries including those of affiliated companies as reported in the

Company's annual FERC Form 1, page 354, line 21, column (b) to the Company's total direct wages and salaries including those of the affiliated companies as reported in the Company's FERC Form 1, page 354, line 28, column (b), and excluding administrative and general wages and salaries as reported in the Company's FERC Form 1, page 354, line 27, column (b).

2. Plant Allocation Factor shall equal the ratio of the sum of Transmission Plant, excluding HQ leases, plus Transmission Related Intangible and General Plant to Total Plant in Service excluding HQ Leases.

B. TERMS

Administrative and General Expense shall equal the expenses as reported in the Company's FERC Form 1, page 323, line 197, column (b), excluding Property Insurance included in FERC Account No. 924, Regulatory Commission Expense included in FERC Account No. 928, and Advertising Expense included in FERC Account No. 930.1 and excluding Merger-Related Costs included in FERC Account Nos. 920-935 (other than those in FERC Account Nos. 924, 928 and 930.1, which have already been excluded). The amount of Postretirement Benefits Other Than Pensions ("PBOP") expense in FERC Account No. 926 shall be separately stated as a footnote to the Company's FERC Form 1, page 323, line 187, column (b): Current Year and column (c): Previous Year.

Amortization of Gain on Reacquired Debt shall equal the amortization amount recorded in FERC Account No. 429.1.

Amortization of Loss on Reacquired Debt shall equal the expenses as recorded in FERC Account No. 428.1.

Amortization of Investment Tax Credits shall equal the credits as recorded in FERC Account No. 411.4.

Depreciation Expense for Transmission Plant shall equal the transmission expenses as recorded in FERC Account No. 403 as reported in the Company's annual FERC Form 1 page 336, line 7, column (f).

General Plant shall equal the gross plant balance as recorded in FERC Account Nos. 389-399.

General Plant Depreciation and Amortization Expense shall equal the general plant expenses as recorded in FERC Account Nos. 403 for depreciable items and 404 for items subject to amortization as reported in the Company's annual FERC Form 1, page 336, line 10, column (f).

General Plant Depreciation Reserve shall equal the general reserve balance as recorded in FERC Account No. 108 and reported in the Company's annual FERC Form 1, page 219, line 28, column (b).

General Plant Amortization Reserve shall equal the general reserve balance as recorded in FERC Account No. 111 and reported in the Company's annual FERC Form 1, page 200 in a footnote to line 14.

Hydro-Quebec DC Facilities (HQ Leases) shall equal the balance in capital leases as recorded in FERC Account Nos. 350-359 and FERC Account Nos. 389-399.

Intangible Plant shall equal the gross plant balance as recorded in FERC Account No. 303 as reported in the Company's annual FERC Form 1, page 205, line 4, column (g). The only allowable Intangible Plant for inclusion in the Local Service Schedule are software, patent or rights costs.

Intangible Plant Amortization Expense shall equal amortization expenses as recorded in FERC Account Nos. 404-405 as reported in the Company's annual FERC Form 1, page 336, line 1, column (f). The only allowable Intangible Plant Amortization Expense for inclusion in the Local Service Schedule is the amortization of software, patent or rights costs.

Intangible Plant Amortization Reserve shall equal the amortization reserve balance as recorded in FERC Account No. 111. The only allowable Intangible Plant Amortization Reserve for inclusion in the Local Service Schedule is that related to the amortization of software, patent or rights costs.

Merger-Related Costs shall equal NSTAR Electric's amortized merger-related costs as authorized by FERC or by state regulatory order.

Other Regulatory Assets/Liabilities - FAS 106 shall equal the net of the FAS 106 balance as recorded in FERC Account No. 182.3 and any FAS 106 balance as recorded in the FERC Account No. 254.

Other Regulatory Assets/Liabilities - FAS 109 shall equal the net of the FAS 109 asset and any FAS 109 balance liability.

Other Regulatory Assets/Liabilities – shall equal NSTAR Electric's unamortized balance of merger-related transmission costs recorded in FERC Account No. 182.3 as authorized by FERC.

Payroll Taxes shall equal those payroll expenses as recorded in the FERC Account No. 408.1.

Plant Held for Future Use shall equal the balance in FERC Account No. 105 that relates to land and land rights which have been purchased for future transmission use, or transmission related projects that were included in this account before January 1, 2007.

Prepayments shall equal the prepayment balance as recorded in FERC Account No. 165, plus any prepayment specifically related to the Company's Pension plans related to electric company operations recorded in FERC Account No. 182.3, Other Regulatory Assets.

Property Insurance shall equal the expenses as recorded in FERC Account No. 924.

Total Accumulated Deferred Income Taxes shall equal the net of the deferred tax balance as recorded in FERC Account Nos. 281-283 and 190 for those balances that are directly related to transmission, excluding those directly related to distribution or other businesses.

Total Gain on Reacquired Debt shall equal the gain as recorded in FERC Account No. 257.

Total Loss on Reacquired Debt shall equal the expenses as recorded in FERC Account No. 189.

Total Municipal Tax Expense shall equal the municipal tax expenses as recorded in FERC Account No. 408.1 as reported in the Company's annual FERC Form 1, page 263, line 10, column (i).

Total Plant in Service shall equal the total gross plant balance as recorded in FERC Account Nos. 301-399 excluding HQ Leases recorded in those accounts.

Total Transmission Depreciation Reserve shall equal the transmission reserve balance as recorded in FERC Account No. 108 as reported in the Company's annual FERC Form 1, page 219, line 25, column (b), excluding HQ-related amounts recorded in that account.

Transmission Depreciation Expense shall be the annual depreciation expense for transmission accounts computed using the following rates, as approved by FERC in Docket No. ER03-1274:

Account	Description	Rate
352	Structures and Improvements	2.19%
353	Station Equipment	2.53%
354	Towers and Fixtures	2.03%
355	Poles and Fixtures	2.25%
356	Overhead Conductors and Devices	2.19%
357	Underground Conduit	2.06%
358	Underground Conductors and Devices	2.15%
359	Roads and Trails	1.63%

Transmission Merger-Related Costs shall equal NSTAR Electric's amortized merger-related transmission costs as authorized by FERC.

Transmission Operation and Maintenance Expense shall equal all transmission-related expenses as recorded in FERC Account Nos. 560-564 and 566-576.5, and shall exclude; (i) all HQ HVDC expenses recorded in those accounts, and (ii) expenses billed to the Company by ISO-NE for Scheduling and Dispatch Service.

Transmission Plant shall equal the balance as recorded in FERC Account Nos. 350-359.1, adjusted to exclude the capital leases in the Hydro-Quebec DC Facilities (HQ Leases).

Transmission Plant Materials and Supplies shall equal the balance as assigned to transmission, as recorded in FERC Account No. 154 as reported in the Company's annual FERC Form 1, page 227, lines 5 and 8, column (c).

II. CALCULATION OF TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirement shall equal the sum of (A) Return and Associated Income Taxes, (B) Transmission Depreciation and Amortization Expense, (C) Transmission Related Amortization of Gain/Loss on Reacquired Debt, (D) Transmission Related Amortization of Investment Tax Credits, (E) Transmission Related Municipal Tax Expense, (F) Transmission Related Payroll Tax Expense, (G) Transmission Operation and Maintenance Expense, (H) Transmission Related Administrative and

General Expenses, (I) Transmission Related Integrated Facilities Charges, minus (J) Transmission Support Revenue, plus (K) Transmission Support Expense, plus (L) Transmission-Related Expense from Generators, minus (M) Transmission Rents Received from Electric Property, minus (N) Short-Term and Non-Firm Point-To-Point Service Revenues, minus (O) Regional Network Services (RNS) Revenues, minus (P) Through or Out Revenues, minus (Q) ISO-NE Scheduling and Dispatch Revenues.

A. Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate.

1. Transmission Investment Base

The Transmission Investment Base will be the year end balances of (a) Transmission Plant, plus (b) Transmission Related Intangible and General Plant, plus (c) Transmission Plant Held for Future Use, plus (d) 50 percent of Transmission Related Construction Work In Progress (CWIP), less (e) Transmission Related Depreciation and Amortization Reserve, less (f) Transmission Related Accumulated Deferred Taxes, less, (g) AFUDC Regulatory Liability, plus (h) Transmission Related Gain/Loss on Reacquired Debt, plus (i) Other Regulatory Assets/Liabilities, plus (j) Transmission Prepayments, plus (k) Transmission Materials and Supplies, plus (l) Transmission Related Cash Working Capital.

(a) Transmission Plant will equal the balance of the investment in Transmission Plant. This value excludes the capital leases in the Hydro-Quebec DC Facilities (HQ Leases).

(b) Transmission Related Intangible and General Plant shall equal the sum of the balance of investment in Intangible Plant and General Plant multiplied by the Transmission Wages and Salaries Allocation Factor.

(c) Transmission Plant Held for Future Use shall equal the land and land rights portion of the balance of Transmission-related Plant Held for Future Use (FERC Account No. 105) plus the non-land Plant Held for Future Use related to projects that were included in Account No. 105 prior to January 1, 2007 to the extent such non-land plant has not been closed to Plant In Service; such balances to be provided in conformance with the FERC Uniform System of Accounts, Instruction E, Account No. 105 which requires that "…property included in this account shall be classified according to detail accounts (301-

399)…and shall be maintained in such detail as though the property were in service."

(d) 50 Percent of Transmission Related Construction Work in Process (CWIP) shall equal the balance of Transmission related investment in FERC Account 107 multiplied by 50%, subject to any exclusions pursuant to the provisions of Section 4.1 of this Local Service Schedule.

(e) Transmission Related Depreciation and Amortization Reserve shall equal the balance of Total Transmission Depreciation Reserve as reported in the Company's annual FERC Form 1, page 219 line 25, column (b), plus the balance of Transmission Related Intangible Plant Amortization Reserve, Transmission Related General Plant Depreciation Reserve and Transmission Related General Plant Amortization Reserve. Transmission Related Intangible Plant Amortization Reserve, Transmission Related General Plant Depreciation Reserve and Transmission Related General Plant Amortization Reserve shall equal the product of (i) the sum of the Intangible Plant Amortization Reserve, General Plant Depreciation Reserve and General Plant Amortization Reserve and (ii) the Transmission Wages and Salaries Allocation Factor. The Total Transmission Depreciation Reserve balance excludes any amounts related to the capital leases in the Hydro-Quebec DC Facilities (HQ Leases).

(f) Transmission Related Accumulated Deferred Taxes shall equal the electric balance of Total Accumulated Deferred Income Taxes (for those balances that are directly related to transmission, plus the balances not directly related to other businesses), with the remaining accumulated deferred taxes not directly related to other businesses being allocated on the same basis used for the related rate base assets.

(g) AFUDC Regulatory Liability shall equal 50% of the capitalized AFUDC booked on transmission projects as recorded in FERC Account No. 254.

(h) Transmission Related Gain/Loss on Reacquired Debt shall equal the electric balance of Total Gain/Loss on Reacquired Debt multiplied by the Plant Allocation Factor.

(i) Other Transmission Related Regulatory Assets/Liabilities shall equal the electric balance of any deferred rate recovery of FAS 106 expenses multiplied by the Transmission

Wages and Salaries Allocation Factor, plus the electric balance of FAS 109 multiplied by the Plant Allocation Factor, plus NSTAR Electric's unamortized balance of merger-related transmission costs recorded in FERC Account No. 182.3 as authorized by FERC.

(j) Transmission Prepayments shall equal the electric balance of Prepayments multiplied by the Transmission Wages and Salaries Allocation Factor.

(k) Transmission Materials and Supplies shall equal the electric balance of Transmission Plant Materials and Supplies.

(l) Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of the Transmission Operation and Maintenance Expense included in Section II.G, Transmission Related Administrative and General Expenses included in Section II.H, and Transmission Support Expenses included in Section II.K.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) the Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital for Service Years ending before January 1, 2013 will be calculated based 70% upon the capital structure at the end of each year and 30% upon a pro-forma capital structure consisting of 50% debt, 0% preferred, and 50% common equity; thereafter the pro-forma capital structure will be the same as the actual capital structure, and will equal the sum of (i), (ii) and (iii) below. Notwithstanding the foregoing, for Service Years ending before January 1, 2013, NSTAR's Weighted Cost of Capital will be the lower of the blended rate as calculated herein or the actual rate.

(i) the long-term debt component, which equals the product of: the actual weighted average embedded cost to maturity of the long-term debt then outstanding; and the sum of (a) the ratio that long-term debt is to the total capital multiplied by 70%, plus (b) 50% pro-forma capital structure multiplied by 30%.

(ii) the preferred component shall be the product of: the embedded cost of preferred stock outstanding at the end of each year; and the sum of (a) the ratio that preferred stock is to the total capital multiplied by 70%, plus (b) 0% pro-forma capital structure multiplied by 30%.

(iii) the return on equity component shall be the product of: the allowed ROE of the common equity; and the sum of (a) the ratio that common equity is to the total capital multiplied by 70%, plus (b) 50% pro-forma capital structure multiplied by 30%. The allowed ROE shall be 10.57%, plus any additional incentive ROE adders as may be applied to specific investment approved by the Commission pursuant to Order No. 679, provided that the total ROE for any project, including any such ROE incentives, shall be capped by the top of the applicable zone of reasonableness determined by FERC for the relevant period. The allowed ROE shall be subject to revision at any time by unilateral filing by NSTAR under Section 205 of the FPA or by such Section 205 filing by NSTAR on a joint basis with other New England transmission owners. In either case, the revised ROE shall become effective no later than sixty days after the filing in accordance with the provisions of the FPA and also subject to any suspension or refund condition which the Commission may order pursuant to its authority under that Section. Any filing made by NSTAR to revise the ROE in compliance with a Commission order shall become effective as of the date specified in such order and shall raise no issue regarding this Local Service Schedule other than the compliance with the Commission order. The allowed ROE is also subject to revision pursuant to the authority of the Commission under Sections 205 and 206 of the FPA.

(b) Federal Income Tax shall equal

$$\frac{(A+[(C+B)/D])(FT)}{1 - FT}$$

where FT is the Federal Income Tax Rate and A is the weighted return on equity component, including preferred, as determined in Sections II.A.2.(a)(ii) and (iii) above, B is Transmission Related Amortization of Investment Tax Credits, as determined in Section II.D below, C is the equity AFUDC component of Transmission Depreciation and Amortization Expense, as defined in Section II.B below, and D is Transmission Investment Base, as determined in Section II.A.1 above.

(c) State Income Tax shall equal

$$\frac{(A+[(C+B)/D] + \text{Federal Income Tax})(ST)}{1 - ST}$$

where ST is the State Income Tax Rate, A is the weighted return on equity component, including preferred, determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section II.D below, C is the equity AFUDC component of Transmission Depreciation and Amortization Expense, as defined in Section II.B below, D is the Transmission Investment Base, as determined in II.A.1 above and Federal Income Tax is the rate determined in Section II.A.2.(b) above.

B. Transmission Depreciation and Amortization Expense shall equal the sum of (i) the Depreciation Expense for Transmission Plant and (ii) an allocation of Intangible Plant Amortization Expense and General Plant Depreciation Expense, which is calculated by multiplying the sum of (a) Intangible Plant Amortization Expense and (b) General Plant Depreciation Expenses by the Transmission Wages and Salaries Allocation Factor; less the Amortization of AFUDC Regulatory Credit as recorded in FERC Account No. 407.4.

C. Transmission Related Amortization of Gain/Loss on Reacquired Debt shall equal the electric Amortization of Gain/Loss on Reacquired Debt multiplied by the Plant Allocation Factor.

D. Transmission Related Amortization of Investment Tax Credits shall equal the electric Amortization of Investment Tax Credits multiplied by the Plant Allocation Factor.

E. Transmission Related Municipal Tax Expense shall equal the total electric municipal tax expense reported in the Company's FERC Form 1, page 263, Local Real Estate and Personal Property Taxes, column (i), multiplied by the Plant Allocation Factor.

F. Transmission Related Payroll Tax Expense shall equal the total electric payroll tax expense reported in the Company's FERC Form 1, page 263, Service Company Allocations and Capitalization, column (i), multiplied by the Transmission Wages and Salaries Allocation Factor.

G. Transmission Operation and Maintenance Expense shall equal the Transmission Operation and

Maintenance Expenses in Section I.B above.

H. Transmission Related Administrative and General Expenses shall equal the sum of the (1) Administrative and General Expense multiplied by the Transmission Wages and Salaries Allocation Factor, (2) Property Insurance included in FERC Account No. 924, line 156 multiplied by the Transmission Plant Allocation Factor, (3) expenses included in Account No. 928(excluding Merger-Related Costs included in Account No. 928), line 160 related to (i) transmission related FERC Assessments, plus (ii) any other Federal and State transmission related expenses or assessments, plus (iii) the cost of any independent audit requested by the Mass AG as the representative for NSTAR's retail customers and (4) Transmission Merger-Related Costs. The amount of PBOP expense shall be separately stated. NSTAR commits to adhere to: (i) the Commission's PBOP policy as expressed in the Commission's December 17, 1992, Statement of Policy in Docket No. PL93-1-000, as the Commission may amend that policy from time to time in the future; and (ii) the provisions of Financial Accounting Statement 106, Employers' Accounting for Postretirement Benefits Other Than Pensions.

I. Transmission Related Integrated Facilities Charges shall equal the transmission payments to Affiliates for use of the integrated transmission facilities of those Affiliates included in FERC Account No. 565.

J. Transmission Support Revenues shall equal the revenue received for transmission support included or includable in FERC Account Nos. 454 and 456 but excluding any revenue received for use of the Company's entitlement in the Hydro-Quebec Facilities.

K. Transmission Support Expense shall equal the expense paid by the Company for transmission support included in FERC Account No. 565, but excluding expenses for the Hydro-Quebec DC Facilities.

L. Transmission-Related Expense from Generators shall equal the expenses from generators that are reflected in a filing made by the Company with the Commission under Section 205 of the Federal Power Act and accepted by the Commission for recovery under the Local Service Schedule and included or includable in FERC Account No. 565.

M. Transmission Rents Received from Electric Property shall equal any FERC Account Nos. 454 and 456 Rents from Electric Property, associated with Transmission Plant but not reflected as a credit in Transmission Support Revenues in Section II.J.

N. Short-Term and Non-Firm Point-to-Point Service Revenues shall equal the applicable wheeling revenues received for Local Point-To-Point Service provided under this Local Service Schedule, including the transmission component of the Company's Third-Party Sales, as recorded in FERC Account Nos. 447 and 456.1.

O. Regional Network Services (RNS) Revenues shall equal the Company's RNS revenues pursuant to the Tariff, as included or includable in FERC Account Nos. 454, 456 and 456.1 but excluding any incremental revenues associated with FERC-approved adders for RTO participation and new investment.

P. Through or Out Revenues shall equal the distribution of revenues received by the Company for Through or Out Service pursuant to the Tariff as included or includable in FERC Account Nos. 454 and 456.1.

Q. ISO-NE Scheduling and Dispatch Revenues shall be the amount of revenues received by the Company from ISO-NE for scheduling and dispatch services pursuant to the Tariff as included or includable in FERC Account Nos. 454, 456 and 456.1.

ATTACHMENT E

INDEX OF LOCAL NETWORK SERVICE CUSTOMERS

Customer	Date of Service Agreement
ANP Blackstone Energy Company	October 1, 2000
Entergy Nuclear Generation Company	September 1, 1999
New England Power Company	September 6, 1996
NSTAR Electric Company	December 24, 1996
Sithe New Boston LLC	September 1, 1998
Sithe Framingham LLC	September 1, 1998
Sithe Mystic LLC	September 1, 1998
Sithe Edgar LLC	September 1, 1998
Sithe West Medway LLC	September 1, 1998
Town of Braintree Municipal Light Dept.	March 1, 1997
Town of Concord Municipal Light Plant	June 21, 2002
Town of Hingham Municipal Light Plant	March 1, 1997
Town of Hull Municipal Light Plant	March 1, 1997
Town of Norwood Municipal Light Dept.	September 6, 1996
Town of Reading Municipal Light Plant	March 1, 1997
Town of Wellesley Municipal Light Plant	June 21, 2002

ATTACHMENT F

FORMULA RATE TEMPLATE

NSTAR Electric Company

Annual Local Network Service Revenue Requirement

Service Year Ended December 31, xxxx

This template does not change the other provisions of this Schedule 21. The template is not a substitute for Schedule 21 language. If an inconsistency between the Schedule 21 language and the template arises, the Schedule 21 language is controlling. The template is illustrative and the actual true-up filing as made from time to time may include format changes or reflect non-material changes required by the Uniform System of Accounts.

Sheet 1

	(a)	(b)	(c)	(d)
Line	Description	Section	Amount	Reference
1	**Investment Base**	II.A.1		
2	Transmission Plant	II.A.1.a	$ -	Sheet 3, Line 1, Col (f)
3	Transmission Related Intangible & General Plant	II.A.1.b	-	Sheet 3, Line 4, Col (f)
4	Transmission Plant Held for Future Use	II.A.1.c	-	Sheet 3, Line 5, Col (f)
5	Transmission Related Construction Work in Progress	II.A.1.d	-	Sheet 3, Line 6, Col (f)
6	Total Plant		-	Sum Lines 2 thru 5
7	Trans Related Depreciation and Amortization Reserve	II.A.1.e	-	Sheet 3, Line 12, Col (f)
8	Transmission Related Accumulated Deferred Taxes	II.A.1.f	-	Sheet 3, Line 20, Col (f)
9	AFUDC Regulatory Liability	II.A.1.g	-	Sheet 3, Line 21, Col (f)
10	Total Net Plant		-	Sum Lines 6 thru 9
11	Transmission Related Gain/Loss on Reacquired Debt	II.A.1.h	-	Sheet 3, Line 22, Col (f)
12	Other Trans Related Regulatory Assets/Liabilities	II.A.1.i	-	Sheet 3, Line 29, Col (f)
13	Transmission Prepayments	II.A.1.j	-	Sheet 3, Line 30, Col (f)
14	Transmission Materials & Supplies	II.A.1.k	-	Sheet 3, Line 31, Col (f)
15	Transmission Related Cash Working Capital	II.A.1.l	-	Sheet 3, Line 36, Col (f)
16	**Total Investment Base**		$ -	Sum Lines 10 thru 15
17	**Revenue Requirement**			
18	Investment Return and Income Taxes	II.A.2	$ -	Sheet 2, Line 39, Col (c)
19	Transmission Depreciation and Amortization Expense	II.B	-	Sheet 4, Line 7, Col (f)
20	Amortization of Gain/Loss on Reacquired Debt	II.C	-	Sheet 4, Line 8, Col (f)
21	Transmission Related Amort. of Investment Tax Credits	II.D	-	Sheet 4, Line 9, Col (f)
22	Transmission Related Municipal Tax Expense	II.E	-	Sheet 4, Line 10, Col (f)
23	Transmission Related Payroll Tax Expense	II.F	-	Sheet 4, Line 11, Col (f)
24	Transmission Operation & Maintenance Expense	II.G	-	Sheet 4, Line 30, Col (f)
25	Trans Related Administrative and General Expense	II.H	-	Sheet 4, Line 44, Col (f)
26	Transmission Related Integrated Facilities Charges	II.I	-	Sheet 5, Line 10, Col (e)
27	Transmission Support Revenues	II.J	-	Sheet 5, Line 15, Col (e)
28	Transmission Support Expense	II.K	-	Sheet 5, Line 20, Col (e)
29	Transmission Related Expense from Generators	II.L	-	Sheet 5, Line 23, Col (e)
30	Transmission Rents Received from Electric Property	II.M	-	Sheet 5, Line 28, Col (e)
31	Short-Term and Non-Firm P-T-P Service Revenues	II.N	-	Sheet 5, Line 31, Col (e)
32	Regional Network Services (RNS) Revenues	II.O	-	Sheet 5, Line 36, Col (e)
33	Through or Out Revenues	II.P	-	Sheet 5, Line 39, Col (e)
34	ISO-NE Scheduling and Dispatch Revenues	II.Q	-	Sheet 5, Line 43, Col (e)
35	**Total LNS Revenue Requirement**		$ -	Sum Lines 18 thru 34
36	Wholesale LNS Revenues Received:			
37	Item # 1		-	
38	Item #2		-	

39	Last Item	-	
40	Total Wholesale LNS Revenue	$ -	Sum Lines 37 thru 39
41	**Total Retail LNS Revenue Requirement**	**$ -**	Line 35 - Line 40
42	Average 12 CP		
43	Sum of Monthly Peaks (kw)	-	FF1: 400.17(b)
44	Average Peak	-	Line 43 / 12
45	Annual Rate per kw	$ -	Line 35 / Line 44
46	Monthly Rate per kw	$ -	Line 45 / 12
47	Daily Rate per kw	$ -	Line 45 / 365

NSTAR Electric Company

Investment Return and Income Taxes

Service Year Ended December 31, xxxx

Sheet 2

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		Tariff		**Capitalization**		**Weighted**	**Equity**	
Line	**Description**	**Section**	**Balance**	**Ratio ***	**Cost ***	**Cost ***	**Cost**	**Reference**
1	**Weighted Cost of Capital**	II.A.2.a						
2	Long Term Debt	II.A.2.a.i	$ -		0.0000%	0.0000%		FF1: Page 112.24(c)
3	Preferred Stock	II.A.2.a.ii	-		0.0000%	0.0000%	0.0000%	FF1: Page 112.3(c)
4	Common Equity	II.A.2.a.iii	-		0.0000%	0.0000%	0.0000%	FF1: Page 112.16(c) - Line 3(c)
5	Total		$ -			0.0000%	0.0000%	Sum Lines 2 thru 4
6	**Investment Return**	II.A.2						
7	Total Investment Base		$ -					Sheet 1, Line 16, Col (c)
8	Weighted Cost of Capital		0.0000%					Line 5, Col (f)
9	Total Return on Investment		$ -					Line 7 * Line 8
10	**Federal Income Tax**	II.A.2.b						
11	A = Equity Cost		0.0000%					Line 5, Col (g)
12	B = Transmission Amortization of ITC		$ -					Sheet 1, Line 21, Col (c)
13	C = Equity AFUDC		-					FF1: Page 117.38
14	Total B + C		-					Line 12 + Line 13
15	D = Investment Base		-					Line 7
16	(B + C) / D		0.00%					Line 14 / Line 15
17	(A + [(C + B) / D]		0.00%					Line 11 + Line 16
18	FT = Federal Income Tax Rate		35.00%					Federal corporate tax rate
19	1 - FT		65.00%					1 - Line 18
20	Federal Tax Factor		0.00000%					Line 17 * Line 18 / Line 19
21	Total Federal Income Taxes		$ -					Line 15 * Line 20
22	**State Income Tax**	II.A.2.c						
23	A = Equity Cost		0.0000%					Line 5, Col (g)
24	B = Transmission Amortization of ITC		$ -					Sheet 1, Line 21, Col (c)
25	C = Equity AFUDC		-					
26	Total B + C		-					Line 24 + Line 25
27	D = Investment Base		-					Line 7
28	(B + C) / D		0.00%					Line 26 / Line 27
29	(A + [(C + B) / D]		0.00%					Line 23 + Line 28
30	ST = State Income Tax Rate		6.50%					Massachusetts corporate tax rate
31	1 - ST		93.50%					1 - Line 30
32	Federal Tax Factor		0.00000%					Line 23
33	State Tax Factor		0.00000%					(Line 29 + Line 32) * Line 30 / Line 31
34	Total State Income Taxes		$ -					Line 27 * Line 33
35	**Investment Return and Income Taxes**	II.A.2						
36	Return on Investment		$ -					Line 9

37	Federal Income Taxes	-	Line 21
38	State Income Taxes	-	Line 34
39	**Total Return and Income Taxes**	**$ -**	Sum Lines 36 thru 38

* Note that weighting and cost are determined on Sheet 7

NSTAR Electric Company

Investment Base

Service Year Ended December 31, xxxx

Sheet 3

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Tariff				**Allocations**	
						LNS	
Line	**Description**	**Section**	**Total**	**Allocator**	**Factor**	**Amount**	**Reference**
1	**Transmission Plant**	II.A.1.a	$ -	Direct	100.0000%	-	FF1: Page 207.58(g)
2	General Plant		-	W&S	0.0000%	-	FF1: Page 207.99(g)
3	Intangible Plant		-	W&S	0.0000%	-	FF1: Page 205.5(g)
4	**Total Intangible & General Plant**	II.A.1.b	-			-	Sum Lines 2 thru 3
5	**Transmission Plant Held for Future Use**	II.A.1.c	-	Direct	100.0000%	-	FF1: Page 214.10&.23(d)
6	**Transmission Related CWIP**	II.A.1.d	-	CWIP	50.0000%	-	FF1: Page 216(b) Trans only
7	**Transmission Related Dep & Amort Reserve**	II.A.1.e					
8	Transmission Accumulated Depreciation		-	Direct	100.0000%	-	FF1: Page 219.25(b)
9	General Plant Accumulated Depreciation		-	W&S	0.0000%	-	FF1: Page 219.28(b)
10	General Plant Accumulated Amortization		-	W&S	0.0000%	-	FF1: Page 200.21(c) Footnote
11	Intangible Plant Accumulated Amortization		-	W&S	0.0000%	-	FF1: Page 200.21(c) Footnote
12	Total Transmission Related Depreciation Reserve		-			-	Sum Lines 8 thru 11
13	**Transmission Accumulated Deferred Taxes**	II.A.1.f					
14	Accumulated Deferred Taxes (190)		-		0.0000%	-	Sheet 8, Line 5, col (d)
15	Accumulated Deferred Income Taxes (281)		-			-	FF1: Page 113.62(c)
16	Accumulated Deferred Taxes - Property (282)		-				FF1: Page 275.9(k)
17	Less Transition Property		-				FF1: Page 275.4(k)
18	Net Acc. Def. Income Taxes - Other Property (282)		-	Plant	0.0000%	-	Sum Lines 16 thru 17
19	Accumulated Deferred Income Taxes - Other (283)		-		0.0000%	-	Sheet 8, Line 10, col (d)
20	Total					-	Sum Lines 17 thru 19
21	**AFUDC Regulatory Liability**	II.A.1.g	-	Direct	100.00%	-	FF1: Page 278.6(f)
22	**Gain/Loss on Reacquired Debt**	II.A.1.h	-	Plant	0.0000%	-	FF1: Page 111.81(c)+113.61(c)
23	**Other Regulatory Assets**	II.A.1.i					
24	Merger Costs			Direct	100.00%		FF1: Page 232
25	FAS 106 (182.3 & 254)		-	W&S	0.0000%	-	FF1: Page 232.1.39(f)+278.(f)
26	FAS 109 (182.3 & 254)		-				FF1: Page 232.1.29(f)
27	Less FAS 109 - Liability (182.3 & 254)		-				FF1: Page 278.2(f)
28	Net FAS 109 (182.3 & 254)		-	Plant	0.0000%	-	Sum Lines 26 thru 27

29	Total Other Regulatory Assets		-			-	Line 24 + Line 25 + line 28
30	**Prepayments**	II.A.1.j	-	W&S	0.0000%	-	FF1: Page 111.57(c)+ 232.2.8(f)
31	**Transmission Materials & Supplies**	II.A.1.k	-	Direct	100.0000%	-	FF1: Page 227.8(c)+227.5(c) Trans
32	**Cash Working Capital**	II.A.1.l					
33	Operation & Maintenance Expense		-	WC	12.50%	-	Sheet 1, Line 24, col (c)
34	Administrative & General Expense		-	WC	12.50%	-	Sheet 1, Line 25, col (c)
35	Transmission Support Expenses		-	WC	12.50%	-	Sheet 1, Line 28, col (c)
36	Total Cash Working Capital		-			-	Sum Lines 33 thru 35

		Allocation	
37	**Description**	**Factor**	**Reference**
38	Direct Allocation (Direct)	100.0000%	
39	Wages & Salary (W&S)	0.0000%	Sheet 6, Line 6(c)
40	Plant Allocation (Plant)	0.0000%	Sheet 6, Line 14(c)
41	Construction Work in Progress Allocation (CWIP)	50.0000%	Sheet 6, Line 15(c)
42	Cash Working Capital (WC)	12.50%	Tariff Section II.A.1.l

NSTAR Electric Company

Transmission Expenses

Service Year Ended December 31, xxxx

Sheet 4

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Tariff		**Allocations**			
Line	**Description**	**Section**	**Total**	**Allocator**	**Factor**	**LNS Amount**	**Reference**
1	**Transmission Depreciation Expense**	II.B					
2	Transmission Depreciation	II.B.i		Direct	100.00%	$ -	FF1: Page 336.7(f)
3	General Plant Depreciation and Amortization	II.B.ii		W&S	0.00%	-	FF1: Page 336.10(f)
4	Amortization of Transmission Related Intangible Plant			W&S	0.00%	-	FF1: Page 336.1(f)
5	Amortization of AFUDC Regulatory Credit		-			-	FF1: Page 278.6(d) (amort)
6	Net Amortization of Transmission Related Intangible Plant		-			-	Sum Lines 4 and 5
7	Total Transmission Depreciation Expense		$ -			$ -	Sum Lines 2, 3 and 6
8	**Amortization of Gain/Loss on Reacquired Debt**	II.C		Plant	0.00%	$ -	FF1: Page 117.64c
9	**Transmission Related Amortization of ITC**	II.D		Plant	0.00%	$ -	FF1: Page 114.19(c)
10	**Transmission Related Municipal Tax Expense**	II.E		Plant	0.00%	$ -	FF1: Page 263.5(i)
11	**Transmission Related Payroll Tax Expense**	II.F		W&S	0.00%	$ -	FF1: Page 263.8i
12	**Transmission Operation and Maintenance Expense**	II.G					
13	Operation Supervision & Engineering (560)			Direct	100.00%	$ -	FF1: Page 321.83(b)
14	Load Dispatching (561)		-	Internal Costs		-	FF1: Page 321.83(b)
15	Load Dispatch - Reliability (561.1)		-	Internal Costs		-	FF1: Page 321.85(b) footnote
16	Load Dispatch-Mon and Oper Trans System (561.2)		-	Internal Costs		-	FF1: Page 321.86(b) footnote
17	Load Dispatch-Trans Service and Scheduling (561.3)		-	Internal Costs		-	FF1: Page 321.87(b) footnote
18	Scheduling, System Control and Dispatch Services (561.4)		-	Internal Costs		-	FF1: Page 321.88(b) footnote

19	Reliability, Planning and Standards Development (561.5)		-	Internal Costs		-	FF1: Page 321.89(b)
20	Transmission Service Studies (561.6)		-	Internal Costs		-	FF1: Page 321.90(b)
21	Generation Interconnection Studies (561.7)		-	Internal Costs		-	FF1: Page 321.91(b)
22	Reliability, Planning and Standards Development (561.8)		-	Internal Costs		-	FF1: Page 321.92(b) footnote
23	Station Expenses (562)		-	Direct	100.00%	-	FF1: Page 321.93(b)
24	Overhead Lines Expenses (563)		-	Direct	100.00%	-	FF1: Page 321.94(b)
25	Underground Lines Expenses (564)		-	Direct	100.00%	-	FF1: Page 321.95(b)
26	Miscellaneous Transmission Expenses (566)		-	Direct	100.00%	-	FF1: Page 321.97(b)
27	Rents (567)		-	Direct	0.00%	-	Sheet 5, Line 7, col (d)
28	Transmission Maintenance (568 - 573)		-	Direct	100.00%	-	FF1: Ppage 321.111(b)
29	Regional Market Expense (575)		-	Internal Costs	0.00%	-	FF1: Ppage 322.131(b)
30	Total Transmission O&M Expense		$ -			$ -	Sum Lines 13 thru 28
31	**Transmission Related A&G Expenses**	II.H					
32	Administrative and General Expenses		$0				FF1: Page 323.197(b)
33	Property Insurance (924)		-				FF1: Page 323.185(b)
34	Employee Pension and Benefits (926)		-				FF1: Page 323.187(b)
35	Regulatory Commission Expense (928)		-				FF1: Page 323.189(b)
36	General Advertising Expense (930.1)		-				FF1: Page 323.191(b)
37	Merger Related Costs		-				FF1: Page 320 FN
38	Sub-Total		-	W&S	0.00%	-	Sum Lines 32 thru 37
39	Property Insurance (924)	II.H.2	-	Plant	0.00%	-	Line 33
40	Employee Pension and Benefits (926) - Note 1	II.H.1	-	W&S	0.00%	-	Line 34
41	Regulatory Commission Expense (928)	II.H.3	-	Footnote	0.00%	-	Line 59
42	General Advertising Expense (930.1)	II.H	-		0.00%	-	Line 36
43	Transmission Merger Related Costs		-	Direct	100.00%	-	FF1: Page 320 FN
44	Total Transmission Related A&G Expenses		$ -			$ -	Sum Lines 39 thru 43
45	Regulatory Commission Expense (928)	II.H.3					
46	DPU - General Assessment		$ -		0.00%	$ -	FF1: Page 350.1 (d)
47	DPU - Appropriation Account		-		0.00%	-	FF1: Page 350.2 (d)
48	DPU - AGO Assessment #1		-		0.00%	-	FF1: Page 350.3 (d)

49	DPU - AGO Assessment #2		-		0.00%	-	FF1: Page 350.4 (d)
50	DPU - Outage Reporting Assessment		-		0.00%	-	FF1: Page 350.5 (d)
51	DPU - Manhole Cover Assessment		-		0.00%	-	FF1: Page 350.6 (d)
52	DPU - Stray Voltage Assessment		-		0.00%	-	FF1: Page 350.7 (d)
53	MA Emergency Management Agency		-		0.00%	-	FF1: Page 350.8 (d)
54	FERC Assessment		-	Direct	100.00%	-	FF1: Page 350.9 (d)
55	FER LICAP Docket		-	Direct	100.00%	-	FF1: Page 350.10 (d)
56	FERC RMR Docket		-	Direct	100.00%	-	FF1: Page 350.11 (d)
57	FERC Docket ER07-549, Including cost of audit		-	Direct	100.00%	-	FF1: Page 350.12 (d)
58	DPU Regulatory Proceeding Costs 05-85		-		0.00%	-	FF1: Page 350.13 (d)
59	Total Regulatory Commission Expenses	II.H.3	-		0.00%	-	Sum Lines 46 thru 58

	Description	Allocation Factor	Reference
60	Direct Allocation (Direct)	100.0000%	
61	Wages & Salaries Allocation (W&S)	0.0000%	Sheet 6, Line 6(c)
62	Plant Allocation (Plant)	0.0000%	Sheet 6, Line 14(c)

63 **Note 1**

64 Included in the Employee Pension and Benefits Expenses are costs related to Post Retirement Benefits other than Pension (PBOP). PBOP costs are determined
65 by an independent actuary as required by FASB 106. The PBOP expense included in Account 926 for 20xx was $xx,xxx,xxx as compared to $xx,xxx,xxx in the prior year;
66 as shown
67 on the FF1, Page 323, footnote. Applying the labor allocator to the total PBOP expense results in $x,xxx,xxx of PBOP expense being recovered through the LNS Tariff
68 in 20xx as compared to $x,xxx,xxx in the prior year.

NSTAR Electric Company

Support Expense & Revenue Detail

Service Year Ended December 31, xxxx

Sheet 5

	(a)	(b)	(c)	(d)	(e)
Line	Description	Tariff Section	Amount	Includable Amount	Reference
1	Transmission Rents (Account 567)	II.G			
2	Hydro Quebec DC Phase I Support			-	FF1: Page 320.98 (b) Footnote
3	Hydro Quebec DC Phase II Support			-	FF1: Page 320.98 (b) Footnote
4	New England Power Support			-	FF1: Page 320.98 (b) Footnote
5	Hydro Quebec Phase II NEP AC, Chester SVC			-	FF1: Page 320.98 (b) Footnote
6	Transmission Line Rents		-	-	FF1: Page 320.98 (b) Footnote
7	Total Transmission Rents Received		-	-	Sum Lines 2 thru 6
8	Transmission Related Integrated Facilities Charges	II.I	-	-	
9	- none -		-	-	
10	Total Trans Related Integrated Facilities Charges		-	-	Sum Lines 9 thru 9
11	Transmission Support Revenues 456 & 456.1	II.J			
12	Item #1			$ -	FF1: Page 300.21(b) Footnote
13	Item # 2			-	FF1: Page 300.21(b) Footnote
14	Last Item		-	-	FF1: Page 300.22(b) Footnote
15	Total Short Term & Non-Firm PTP Revenues		$ -	$ -	Sum Lines 12 thru 14
16	Transmission Support Expense (565)	II.K			
17	Item #1			-	FF1 Q2: Page 332.2(h)
18	Item # 2			-	FF1 Q3: Page 332.2(h)
19	Last Item		-	-	FF1: Page 332.2(h)
20	Total Transmission Support Expense		-	-	Sum Lines 17 thru 19
21	Transmission Related Expense from Generators	II.L			N/A
22	- none -		-	-	
23	Total Trans Related Expense from Generators		-	-	Sum Lines 22 thru 22
24	Rents Received from Electric Property (454)	II.M			
25	Item #1			-	FF1: Page 300.19(b) Footnote
26	Item # 2			-	FF1: Page 300.19(b) Footnote
27	Last Item		-	-	FF1: Page 300.19(b) Footnote
28	Total Rents Received		-	-	Sum Lines 25 thru 27
29	Short-Term and Non-Firm Point-to-Point Rev	II.N	$ -	$ -	N/A
30	- none -		-	-	
31	Total ST and Non-Firm Point-to-Point Revenues		-	-	Sum Lines 30 thru 30
32	Regional Network Service Revenues (456):	II.O			
33	RNS Transmission Revenue		-	-	
34	RNS PTF Post 2003 investment 1 % Adder		-	-	RNS Revenue Requirement
35	RNS PTF RTO Participation 0.5% Adder		-	-	RNS Revenue Requirement

36	Total Regional Network Services Revenues		-	-	Sum Lines 33 thru 35
37	Through or Out Revenues	II.P	$ -	$ -	N/A
38	- none -		-	-	
39	Total Through or Out Revenue		-	-	Sum Lines 38 thru 38
40	ISO-NE Scheduling & Dispatch Revenue	II.Q			
41	Nepool Scheduling & Dispatch Revenue		-	-	
42	RTO Participation 0.5% Adder		-	-	Reguional Schedule 1 Revenue Requirement
43	Total ISO-NE Scheduling & Dispatch Revenue		-	-	Sum Lines 42 thru 42

NSTAR Electric Company

Allocation Factors

Service Year Ended December 31, xxxx

Sheet 6

	(a)	(b)	(c)	(d)
Line	**Description**	**Tariff Section**	**Amount**	**Reference**
	Transmission Wages & Salaries Allocation			
1	**Factor**	I.A.1		
2	Transmission Related Direct Wages & Salaries		$ -	FF1: Page 354.21(b)
3	Total Direct Wages & Salaries		-	FF1: Page 354.28(b)
4	Administrative & General Wages & Salaries		-	FF1: Page 354.27(b)
5	Net Total Direct Wages & Salaries		-	Line 3 less Line 4
6	Transmission Wages & Salaries Allocation Factor		**0.0000%**	Line 2 / Line 5
7	**Plant Allocation Factor**	I.A.2		
8	Transmission Plant Investment		$ -	FF1: Page 207.58(g)
9	HQ Leases		-	
10	Transmission Related General Plant		-	Sheet 3, Line 2, Col (f)
11	Transmission Related Intangible Plant		-	Sheet 3, Line 3, Col (f)
12	Total Transmission Plant Investment		-	Sum Lines 8 thru 11
13	Total Plant in Service		-	FF1: Page 207.104(g)
14	Plant Allocation Factor		**0.0000%**	Line 12 / Line 13

15	**Construction Work in Progress Allocation Factor**	II.A.1.d	**50.0000%**

NSTAR Electric Company

Cost of Long Term Debt

Service Year Ended December 31, xxxx

Sheet 7

Line	Series	Dated	Term (Years)	Coupon Rate	Original Issue	Principal Amount Outstanding	Percent of Total	Debt Disc & Exp	Call Premium on Debt	Net Proceeds	Cost to Maturity	Weighted Cost	Reference
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	FF1:256(a)	FF1:256(d)		FF1:256(e)	FF1:256(b)	FF1:256(h)		FF1:256(c)					
	Long Term Debt												
							Col f / Col f Total			**Col f - Col h - Col i**	**Col d + ((Col h + Col i) / (Col e / Col d))**	Col h * Col g	
1	MIFA Bonds	2/8/94	20	5.75%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
2	4.875% Debentures	4/13/04	10	4.875%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
3	7.8% Debentures	5/10/95	15	7.80%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
4	4.875 Debentures	10/9/02	10	4.875%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
5	5.75% Debentures	3/13/06	30	5.750%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
6	5.625% Debentures	11/19/07	10	5.63%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
7	Total				$ -	$ -	0.00%	$ -	$ -	$ -		0.0000%	Sum Lines 1 Thru 6

Cost of Preferred Stock

	FF1:250(a)			FF1:250(a)		FF1:250(f)			
		Preferred Stock				Principal			
				Coupon	Original	Amount	Percent	Weighted	
	Series	Dated	Term	Rate	Issue	Outstanding	of Total	Cost	Reference
8	4.25%	6/13/1956	N/A	4.25%			0	0.0000%	FF1: Page 250 & 251
9	4.78%	7/10/1958	N/A	4.78%			0	0.0000%	FF1: Page 250 & 251
10	Total				$ -	$ -	0.00%	0.0000%	Sum Lines 8 Thru 9

Effective NSTAR ROI

Tariff Section II.A.2.a

	(a)	(b)	(c)	(d)	(e)	(f)
Line	**Description**	**Common**	**Preferred**	**LTD**	**Total**	**Reference**
11	Amount			$	-	Sheet 2, lines 2 thru 4
12	Cost	0.0000%	0.0000%	0.0000%		See Note
13	Actual Weighting	0.0000%	0.0000%	0.0000%	0.0000%	Line 11 / Total Line 11
14	Weighted Cost	0.0000%	0.0000%	0.0000%	0.0000%	Line 12 * Line 13
15	70% of Weighted Cost	0.0000%	0.0000%	0.0000%		Line 14 * 70%
16	Tariff Weighting	50.0000%	0.0000%	50.0000%	100.0000%	Tariff Section II.A.2.a
17	Weighted Cost	0.0000%	0.0000%	0.0000%	0.0000%	Line 12 * Line 16
18	30% of Weighted Cost	0.0000%	0.0000%	0.0000%		Line 17 * 30%
19	Blended Cost of Capital	0.0000%	0.0000%	0.0000%	0.0000%	Line 15 + Line 18

20	**Lower of Blended or Actual**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	Lower of line 14, col (e) or line 19, col (e) Tariff Section II.A.2.a
21	Note:					
22	The Regurn on Equity component is specified in Tariff Section II.A.2.a.iii					
23	The Cost of Preferred Stock is calculated on line 10					
24	The Cost of Long Term Debt is calculated on line 7					

NSTAR Electric Company

Annual Local Network Service Revenue Requirement

Service Year Ended December 31, xxxx

Sheet 8

Transmission Related ADIT - Tariff Section II.A.1.f

	(a)	(b)	(c)	(d)	(e)
Line	Description	Amount	Allocator	Rate Base	Notes
1	**Account 190**				
2	Item # 1		0.0000%	$ -	FF1: Page 234.2(c) Footnote
3	Item #2		0.0000%	-	FF1: Page 234.2(c) Footnote
4	Last Item	-	0.0000%	-	FF1: Page 234.2(c) Footnote
5	Total 190	$ -	0.0000%	$ -	Sum Lines 2 thru 4
6	**Account 283**				
7	Item # 1		0.0000%	-	FF1: Page 276.3(k) Footnote
8	Item #2		0.0000%	-	FF1: Page 276.3(k) Footnote
9	Last Item	-	0.0000%	-	FF1: Page 276.3(k) Footnote
10	Total 283	$ -	0.0000%	$ -	Sum Lines 7 thru 9
11	Wages & Salary Allocator	0.0000%			Sheet 6, Line 6, Col (d)
12	Plant Allocator	0.0000%			Sheet 6, Line 14, Col (d)

ATTACHMENT L

CREDITWORTHINESS POLICY

I. General Information:

This Attachment L details the specific requirements for the creditworthiness procedures of NSTAR. All customers taking (i) any service under Schedule 21-NSTAR or (ii) any FERC-regulated interconnection service from NSTAR must meet the terms of this Policy (where all the above, collectively, are referred to as "Services"). The creditworthiness of each customer must be established prior to receiving service from NSTAR. A customer will be evaluated at the time its application for service is provided to NSTAR. A credit review shall be conducted for each transmission customer not less than annually or upon reasonable request by the transmission customer. This Attachment L, when updated, will be done so in accordance with Section 10 of this Policy and as posted on NSTAR's OASIS.

All customers must comply with the terms of this Attachment L. Each customer should refer to NSTAR's web site at www.nstar.com, or NSTAR's OASIS site, for the NSTAR representative to whom to forward the information required by this Attachment L.

Upon receipt of a customer's information, NSTAR will review it for completeness and will notify the customer if additional information is required. Upon completion of an evaluation of a customer, NSTAR will notify the customer of its Financial Assurance requirements. NSTAR will provide a written evaluation, upon request, to customers who are not required to provide Financial Assurance.

II. Financial Information:

Customers receiving transmission service or requesting interconnection service must submit, if available, the following:

- All current rating agency reports from Standard and Poor's ("S&P"), Moody's and/or Fitch of the customer.
- Audited financial statements provided by a registered independent auditor for the two most recent years, or the period of its existence, if shorter, for the customer.

III. Creditworthiness Requirements:

A. The customer must meet at least one of the following quantitative criteria in order to receive unsecured credit equivalent to 3 months of transmission charges or, for interconnections, the credit equivalent of 3 months of the annual facilities charges and other ongoing charges:

i) If rated, the customer must have either for itself or for its outstanding debt the following:

- Standard and Poor's or Fitch rating of at least a BBB, or
- Moody's rating of at least a Baa2.

ii) If un-rated or if rated below BBB/Baa2, as stated in a), the customer must meet all of the following:

- A Current Ratio of at least 1.0 times (current assets divided by all current liabilities);
- A Total Capitalization Ratio of less that 60% debt: total debt (including all short-term borrowing) divided by total shareholders' equity plus total debt;
- "Earnings before interest, taxes, depreciation and amortization" in most recent fiscal quarter divided by expense for interest" (EBITDA-to-Interest Expense Ratio) of at least 2.0 times; and
- Audited Financial Statement with an unqualified audit opinion.

iii) If the customer relies on the creditworthiness of a parent company, the customer's parent company must meet the criteria set out in (a) or (b) above, and must provide to NSTAR a written guarantee that it will be unconditionally responsible for all financial obligations associated with the customer's receipt of transmission service from NSTAR.

iv) If the customer is a municipal that is a member of the Massachusetts Municipals Wholesale Electric Cooperative (MMWEC), MMWEC must meet the criteria set out in (a) or (b) above and provide to NSTAR a written guarantee that MMWEC will be unconditionally responsible for all financial obligations associated with the customer's receipt of transmission service from NSTAR.

B. If the customer does not qualify for unsecured credit under Section A, the customer will qualify

for unsecured credit equivalent to two months of transmission service charges, or for interconnections, the credit equivalent of two months of the annual facilities charges and other ongoing charges, if one of the following qualitative factors is met:

- ? The customer has, on a rolling basis, 12 consecutive months of payments to NSTAR with no missed, late or defaults in payment; or
- ? The customer has an executed long-term contract for the sale of the full output (energy and capacity) of its generating unit and either has executed a corresponding service agreement under Schedule 21-NSTAR for the transmission of that output or the execution of such a service agreement is pending the customer's demonstration of creditworthiness pursuant to this Attachment L.

IV. Financial Assurance:

If the customer does not meet the applicable requirements for Creditworthiness set out in Section III above, then the customer must either:

- Pay in advance for service an amount equal to the lesser of the total charge for Transmission Service or the charge for three months of Transmission Service not less than 5 days in advance of the commencement of service; or

- Obtain Financial Assurance in the form of a: letter of credit, performance bond, or corporate guarantee equal to the equivalent of 3 months of Transmission Service charges prior to receiving service.

If the customer pays for service in advance, NSTAR will pay to the customer interest on the amounts not yet due to NSTAR , computed in accordance with the Commission's regulations at 18 CFR ? 35.19a(a)(2)(iii).

V. Contesting Creditworthiness Determination:

The Transmission Customer may contest NSTAR's determination of creditworthiness by submitting a written request for re-evaluation within 20 calendar days of being notified of the creditworthiness determination. Such request should provide information supporting the basis for a request to re-evaluate a

Transmission Customer's creditworthiness. NSTAR will review and respond to the request within 20 calendar days.

VI. Process for Changing Credit Requirements:

In the event that NSTAR plans to revise its requirements for credit levels or collateral requirements as detailed in this Attachment L, NSTAR shall submit such changes in a filing to the Commission under Section 205 of the Federal Power Act. NSTAR shall follow the notification requirements pursuant to Section 3.04(a) of the Transmission Operating Agreement and reflected herein.

A. General Notification Process

i) NSTAR shall provide written notification to ISO-NE and stakeholders of any filing described above, at least 30 days in advance of such filing.

ii) Filing notifications shall include a detailed description of the filing, including a redlined document containing revised change(s).

iii) NSTAR shall consult with interested stakeholders upon request.

iv) Following Commission acceptance of such filing and upon the effective date, NSTAR shall revise Attachment L and an updated version of Schedule 21-NSTAR shall be posted the ISO-NE website.

B. Transmission Customer Responsibility

When there is a change in requirements pursuant to this Attachment L, it is the responsibility of the customers to forward updated financial information to NSTAR at the address noted on NSTAR's OASIS site and indicate whether the change affects their ability to meet the requirements of this Attachment L. In such cases where the customer's status has changed, the customer must take the necessary steps to comply with the revised requirements of the Attachment L by the effective date of the change.

VII. Posting Collateral Requirements:

A. Changes in Customer's Financial Condition

Each customer must inform NSTAR, in writing, within five (5) business days of any material change in its financial condition, and, if the customer qualifies under Section III.A(c), that of its parent company. A material change in financial condition may include, but is not limited to, the following:

- Change in ownership by way of a merger, acquisition or substantial sale of assets;
- A downgrade of long- or short-term debt rating by a major rating agency;
- Being placed on a credit watch with negative implications by a major rating agency;
- A bankruptcy filing;
- Any action requiring filing of a Form 8-K;
- A declaration of or acknowledgement of insolvency;
- A report of a significant quarterly loss or decline in earnings;
- The resignation of key officer(s);
- The issuance of a regulatory order and/or the filing of a lawsuit that could materially adversely impact current or future financial results.

B. Change in Creditworthiness Status

- A customer who has been extended unsecured credit under this policy must comply with the terms of Financial Assurance in Section IV above if one or more of the following conditions apply:
- The customer no longer meets the applicable criteria for Creditworthiness in Section III above;
- The customer exceeds the amount of unsecured credit extended by NSTAR, in which case Financial Assurance equal to the amount of excess must be provided within 5 business days; or
- The customer has missed two or more payments for any of the services offered by NSTAR in the last 12 months.

In the event that NSTAR determines that there is a change in the credit level or collateral requirements, the customer may request a written explanation of the basis for this change. Such notification should be

sent to the NSTAR contact indicated on the NSTAR OASIS site. NSTAR shall respond to such request within 20 days of receipt of such notification.

Unless otherwise noted above, when there is a change in a customer's Creditworthiness Status requiring the customer to provide Financial Assurance, the customer must provide such Financial Assurance within 20 business days from the date the customer either notifies NSTAR, as required in Section VI.B above, or receives notice from NSTAR.

VIII. Ongoing Financial Review:

Each customer is required to submit to NSTAR annually or when issued, as applicable:

- Current rating agency report;
- Audited financial statements from a registered independent auditor; and
- 10-Ks and 8-Ks, promptly upon their issuance.

IX. Suspension of Service:

NSTAR may immediately suspend service (with notification to Commission) to a customer, and may initiate proceedings with Commission to terminate service, if the customer does not meet the terms described in Sections III through VIII above at any time during the term of service or if the customer's payment obligations to NSTAR exceed the amount of unsecured or secured credit to which it is entitled under this Attachment L. A customer is not obligated to pay for transmission service that is not provided as a result of a suspension of service.

Eversource

SCHEDULE 21-ES

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Attachment ES-I: Annual Localized Transmission Revenue Requirement

Attachment ES-L: Creditworthiness Procedures

SCHEDULE 21-ES

LOCAL SERVICE SCHEDULE

This Local Service Schedule, designated Schedule 21-ES, governs the terms and conditions of service taken by Transmission Customers over the Transmission System of The Connecticut Light and Power Company, Public Service Company of New Hampshire and Western Massachusetts Electric Company (together, “Eversource”), but not over the Transmission System of their affiliate, NSTAR Electric Company, which provides service pursuant to Schedule 21-NSTAR.

I. COMMON SERVICE PROVISIONS

1 Definitions

Capitalized terms not defined herein shall have the meanings given them in the Tariff.

1.1 Annual Transmission Costs

The total annual cost of the Transmission System for purposes of Local Network Service shall be the amount specified in Attachments ES-H and ES-I, until amended by Eversource or modified by the Commission.

1.2 Annual True Up

The reconciliation to actual costs and actual loads of the estimated costs and loads costs used for billing purposes under Section 3.0 of this Local Service Schedule for any Service Year.

1.3 Category A Load Ratio Share

Ratio of a Transmission Customer's Category A Network Load to Eversource’s total load computed in accordance with Sections 16.5 and 16.6 under Part III of this Local Service Schedule and calculated on a rolling twelve month basis. Also referred to as “Load Ratio Share”.

1.4 Category B Load Ratio Share

Ratio of a Transmission Customer’s Monthly Category B Load in the Designated State or Area for a Localized Facility to the Monthly Transmission System Category B Load for such Designated State or Area, calculated in accordance with Sections 16.5 and 16.6, and calculated on a rolling twelve month basis.

1.5 Designated Agent

See Tariff. Also, the Designated Agent of Eversource is Eversource Energy Service Company ("Eversource Service") which is a subsidiary of Eversource Energy.

1.6 Designated State or Area

The state or area to which the Commission allocates the costs of a Localized Facility identified in Section 16.3.

1.7 **Interest**

The amount computed in accordance with the Commission's regulations at 18 CFR §35.19a (a)(2)(iii). Interest on deposits and shall be calculated from the day the deposit check is credited to Eversource's account.

1.8 **Interruption**

A reduction in non-firm transmission service due to economic reasons pursuant to Schedule 21.

1.9 **Localized** Facility

Facility or costs that the New England System Operator determines should not be included in Attachment F of the ISO OATT.

1.10 **Network Load**

The load that a Network Customer designates for Local Network Service. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements for any Point-To-Point Transmission Service that may be necessary for such non-designated load.

1.11 **Network Operating Agreement**

An executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Local Network Service under Part III of this Local Service Schedule.

1.12 **Network Upgrades**

Modifications or additions to transmission-related facilities that are integrated with and support Eversource's overall Transmission System for the general benefit of all users of such Transmission System.

1.13 **New England System Operator**

ISO New England Inc. ("ISO") or its successor entity.

1.14 **Party(ies)**

Eversource and the Transmission Customer receiving service under the Tariff.

1.15 **Short-Term Firm Point-To-Point Transmission Service**

Firm Point-To-Point Transmission Service with a term of less than one year.

1.16 Service Agreement

Service Agreement is a transmission service agreement for transmission service provided under this Local Service Schedule or Localized Costs Responsibility Agreement ("LCRA").

1.17 **Service Year**

The calendar year in which the Transmission Customer is receiving service under this Local Service Schedule.

1.18 **Eversource**

The Connecticut Light and Power Company, Western Massachusetts Electric Company, and Public Service Company of New Hampshire, each an operating company of Eversource Energy, but excluding their affiliate NSTAR Electric Company, which provides Transmission Service pursuant to Schedule 21-NSTAR.

1.19 **Eversource's Monthly Transmission System Peak**

The maximum firm usage of the Eversource Transmission System in a calendar month (this does not include load of Eversource's customers exclusively connected to PTF).

1.20 **Eversource Transmission System**

The PTF and non-PTF facilities owned, controlled or operated by Eversource that are used to provide transmission service under this Local Service Schedule. This includes PTF facilities whose costs are not included in the regional rate.

1.21 **Transmission Service**

Point-To-Point Transmission Service provided under this Local Service Schedule on a firm and non-firm basis.

2. Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. Eversource is required to provide (or offer to arrange with the New England System Operator as discussed below), and the Transmission Customer is required to purchase, the following Ancillary Service (i) Scheduling, System Control and Dispatch.

The Transmission Customer serving load within the Eversource Control Area shall also obtain the following ancillary services: (i) Reactive Supply and Voltage Control from Generation Sources, (ii) Regulation and Frequency Response, (iii) Energy Imbalance, (iv) Operating Reserve - Spinning, and (v) Operating Reserve - Supplemental.

The Transmission Customer serving load within the Eversource Control Area is required to acquire the appropriate Ancillary Services, whether from the New England System Operator, Eversource, another party, or by self-supply.

The Transmission Customer may not decline Eversource's or the New England System Operator's offer of appropriate Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from Eversource.

If Eversource is unable to provide Scheduling, System Control and Dispatch, Eversource can fulfill its obligation to provide this Ancillary Service by acting as the Transmission Customer's agent to secure this Ancillary Service from the New England System Operator. The Transmission Customer may elect to (i) have Eversource act as its agent to obtain Scheduling, System Control and Dispatch, (ii) secure Scheduling, System Control and Dispatch directly from the New England System Operator, or from a third party.

Eversource or New England System Operator shall specify the rate treatment and all related terms and conditions in the event of an unauthorized use of Ancillary Services by the Transmission Customer.

The specific Ancillary Services, prices and/or compensation methods are described on the Schedule that is attached to and made a part of the Tariff. Three principal requirements apply to discounts for Ancillary Services provided by Eversource in conjunction with its provision of transmission service as follows: (1) any offer of a discount made by Eversource must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one’s wholesale merchant or an Affiliate’s use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. A discount agreed upon for an Ancillary Service must be offered for the same period to all Eligible Customers on the Eversource system.

3. Billing and Payment

3.1 **Billing Procedure**

Within a reasonable time after the first day of each month, Eversource Service shall submit an invoice to the Transmission Customer for the charges for all services furnished or costs allocated under the Tariff during the preceding month.

The invoice shall be paid by the Transmission Customer within twenty five (25) days of the date of the invoice. All payments shall be made in immediately available funds payable to Eversource Service, or by wire transfer to a bank named by Eversource Service. Billing hereunder shall be based on cost estimates made by Eversource subject to Annual True-up when actual costs for the Service Year are known. Such Annual True-up shall occur no later than six (6) months after the close of the Service Year to which the Annual True-up relates. The Annual True-up will include interest calculated in accordance with Section 35.19a of the Commission’s regulations. If the in

service date of a forecasted capital addition changes, and the impact of such change on Eversource's annual revenue requirement is ten percent or more, Eversource Service will adjust current billing to the Transmission Customer as appropriate.

3.2 Interest on Unpaid Balances

Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by Eversource Service.

3.3 Customer Default

In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to Eversource Service on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after Eversource Service notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, Eversource may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between Eversource and the Transmission Customer, Eversource will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then Eversource may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy. Neither Party shall have the right to challenge any monthly bill or to bring any court or administrative action of any kind questioning the propriety of any bill after a period of twenty four (24) months from the date the bill was due; provided, however, that in the case of a bill based on estimates, such twenty-four month period shall run from the due date of the final adjusted bill.

3.4 Transmission Customer Right to Audit

Eversource shall keep complete and accurate accounts and records with respect to its performance under this Local Service Schedule and shall maintain such data for a period of at least two (2)

years after final billing for audit by a Transmission Customer. The Transmission Customer shall provide thirty (30) days' written notice to Eversource to request an audit of all such accounts and records relevant to service provided to the Transmission Customer for a specific time period. The Transmission Customer shall have the right, during normal business hours and at its own expense, to examine, inspect and make copies of all such accounts and records relevant to service provided to the Transmission Customer at such offices where such accounts and records are maintained, insofar as may be necessary for the purpose of ascertaining the reasonableness and accuracy of all relevant data, estimates or statements of charges submitted hereunder to the Transmission Customer. The records made available to a Transmission Customer for auditing purposes hereunder shall not include information pertaining to the loads of or charges to an individual customer other than the Transmission Customer; unless the Transmission Customer requests that the Commission order that such information be made available to the Transmission Customer and the Commission so orders. Nothing in this section shall be interpreted as limiting the Transmission Customer's access to system-wide load or charge data.

3.5 Regulatory Oversight of Formula Rate

Eversource will submit to the Connecticut Public Utilities Regulatory Authority, the Massachusetts Department of Public Utilities and the New Hampshire Public Utilities Commission ("State Commissions") the following information:

(a) A copy of the New England Power Pool's ("NEPOOL's") or any successor's annual informational filing at FERC supporting the total transmission revenue requirement for New England, which contains information submitted by Eversource supporting its total transmission revenue requirement;

(b) Eversource's total transmission revenue requirement as calculated in Attachments H & I under Schedule 21-ES;

(c) A copy of Eversource's applications under Restated NEPOOL Agreement Section 15.5, concerning the installation of or material changes to transmission facilities (or any successor approval process), and Section 18.4, concerning plans for additions, retirements, or changes in the capacity of transmission facilities (including descriptions of facilities and cost estimates);

(d) A copy of ISO New England's or any successor's Regional Transmission System Plan, which contains all identified improvements to the New England power system approved by the ISO New England or any successor's board;

(e) A copy of Eversource's filing to each New England state's siting council for those projects to be recovered through the RNS or LNS rates, such copy to be filed with the State Commissions when the estimated costs of the projects in question are proposed to be included in the RNS and LNS rates;

(f) At the same time that new estimated rates are implemented, the estimated cost for each capital addition (on a project-by-project basis) the cost of which is to be included in the estimated rates; and, for each such capital addition with an estimated cost of $20 million or greater, Eversource will provide the following to the extent available: (i) a breakdown of the projected cost into the following categories: labor (broken down into planning, engineering, construction, and other), outside services (broken down into planning, engineering, construction and other), materials (broken down into station equipment, towers and poles, overhead conductor, underground conduit and conductor, and other), land (broken down into fee ownership, easement, and other), and other (if applicable) and (ii) a non-binding estimate of the total project costs by calendar quarter;

(g) Within 60 days after the true-up is rendered for a year, the actual cost for each capital addition that was placed in service during that year; and, for each such capital addition with an actual or estimated cost of $20 million or greater, Eversource will provide the following to the extent available: (i) a breakdown of the actual cost into the following categories: labor (broken down into planning, engineering, construction, and other), outside services (broken down into planning, engineering, construction, and other), materials (broken down into station equipment, towers and poles, overhead conductor, underground conduit and conductor, and other), land (broken down into fee ownership, easement, and other), and other (if applicable) and (ii) the actual total project costs by calendar quarter.

4. Regulatory Filings

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the right of Eversource to unilaterally make application to the Commission for a change in rates, terms and

conditions, charges, classification of service, Service Agreement, rule or regulation under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the ability of any Party receiving service under the Tariff to exercise its rights under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

5. Creditworthiness: See Attachment ES-L to this Schedule 21-ES.

6. Rights Under The Federal Power Act

Nothing in this section shall restrict the rights of any party to file a complaint with the Commission under relevant provisions of the Federal Power Act.

II. POINT-TO-POINT TRANSMISSION SERVICE

Scheduling of Point-To-Point Transmission Service:

The System Operator will dispatch all resources subject to its control, pursuant to Market Rule 1, in order to meet load and to accommodate external transactions. Resources within the New England Control Area using Firm Point-to-Point Transmission Service shall be dispatched based on economic merit in accordance with Market Rule 1 and will have no physical scheduling or dispatch rights. Transmission Customers will be charged for congestion costs and any other costs associated with such dispatch in accordance with Market Rule 1.

7. Nature of Firm Point-To-Point Transmission Service

7.1 Classification of Firm Transmission Service

The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedule ES-2, as appropriate, for Long and Short-Term Firm Point-To-Point Transmission Service. In the event that either a Transmission Customer has not made a capacity reservation, or a Transmission Customer exceeds its firm capacity reservation at the Point of Receipt and Point of Delivery the Transmission Customer shall be billed and pay for its actual use of such excess capacity in addition to any Reserved Capacity pursuant to Schedule ES-2, including ancillary services provided pursuant to Schedule ES-1 hereto.

8. Nature of Non-Firm Point-To-Point Transmission Service

8.1 Classification of Non-Firm Point-To-Point Transmission Service

The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedule ES-3, as appropriate, for non-firm Point-To-Point Transmission Service. In the event that either a Transmission Customer has not made a capacity reservation, or a Transmission Customer exceeds its non-firm capacity reservation at any Point of Receipt or Point of Delivery, the Transmission Customer shall be billed and pay for its actual use of such excess capacity in addition to any Reserved Capacity pursuant to Schedule ES-3, including ancillary services provided pursuant to Schedule ES-1 hereto. Non-Firm Point-To-Point Transmission Service shall include transmission of energy on an hourly basis and transmission of scheduled short-term capacity and/or energy on a daily, weekly or monthly basis, but not to exceed one month's reservation for any one Application, under Schedule ES-3.

9. Service Availability

9.1 Real Power Losses

Real Power Losses are associated with all transmission service. Eversource is not obligated to provide Real Power Losses. The Transmission Customer is responsible for replacing losses associated with all transmission service as determined under Market Rule 1. The applicable Real Power Loss factors are as follows:

The amount of transmission losses incurred in transmitting power from the POR(s) to the POD(s) ("Loss Amount") shall be determined from time to time by the New England System Operator in accordance with ISO procedures applicable at the time of delivery. The Loss Amounts, when determined by the New England System Operator, shall be posted on Eversource's Open Access Same-Time Information System ("OASIS"). In the event that the New England System Operator, for any reason, does not determine the entire Loss Amount, the losses not determined by the New England System Operator shall be based on average system losses as set forth below:

Cumulative Losses in Percent

POR/POD	Peak*	Off-Peak	24 Hr. Avg.
Bulk Transmission	1.98	2.42	2.21
Bulk Substation	2.46	2.92	2.70
Pri. Distribution	4.58	4.50	4.54

*Peak hours are defined as 0700-2300, Monday-Friday; Off-Peak hours are all other hours.

10. Procedures for Arranging Firm Point-To-Point Transmission Service

10.1 Deposit

A Completed Application for Firm Point-To-Point Transmission Service also shall include a deposit of either three month's charge for Reserved Capacity or the full charge for Reserved Capacity for service requests of less than one month.

11. Additional Study Procedures For Firm Point-To-Point Transmission Service Requests:

11.1 Disbursement Methodology for Late Study Penalties

See Attachment ES-D to Schedule 21-ES.

12. Compensation for Transmission Service

The Transmission Customers taking Point-To-Point Transmission Service shall pay Eversource for any Direct Assignment Facilities, Ancillary Services and applicable study costs, along with the following:

12.1 Rates and Charges for Transmission Service

Rates for Firm and Non-Firm Point-To-Point Transmission Services are provided in the Attachments appended to this Local Service Schedule: Firm Point-To-Point Transmission Services (Schedule ES-2); and Non-Firm Point-To-Point Transmission Services (Schedule ES-3).

12.2 Rates for Firm and Non-Firm Point-To-Point Transmission Services

Rates for Firm and Non-Firm Point to Point Transmission Services shall be determined as set forth in Attachments ES-2 and ES-3 of this Local Service Schedule on the basis of estimated

costs for each Service Year until the actual costs for such Service Year are determined. Thereafter, payments made on such estimated costs shall be recalculated based on actual data for that Service Year, and an appropriate billing adjustment shall be made pursuant to Section 3 of this Local Service Schedule. Eversource shall use Part II of the Tariff to make its Third-Party Sales. Eversource shall account for such use at the applicable Tariff rates.

III. LOCAL NETWORK SERVICE

13. Nature of Local Network Service

13.1 Real Power Losses

Real Power Losses are associated with all transmission service. Eversource is not obligated to provide Real Power Losses. The Network Customer is responsible for replacing losses associated with all transmission service as determined under Market Rule 1. The applicable Real Power Loss factors are as follows:

The amount of transmission losses incurred in transmitting power across the Eversource Transmission System to the Network Customer's Network Load shall be determined from time to time by the New England System Operator in accordance with ISO procedures applicable at the time of delivery. The Loss Amounts, when determined by the New England System Operator, shall be posted on the Open Access Same-Time Information System ("OASIS"). In the event that the New England System Operator, for any reason, does not determine the entire Loss Amount, the losses not determined by the New England System Operator shall be based on average system losses as set forth below:

Cumulative Losses in Percent

POR/POD	Peak*	Off-Peak	24 Hr. Avg.
Bulk Transmission	1.98	2.42	2.21
Bulk Substation	2.46	2.92	2.70
Pri. Distribution	4.58	4.50	4.54

*Peak hours are defined as 0700-2300, Monday-Friday; Off-Peak hours are all other hours.

14. Network Resources

14.1 Use of Interface Capacity by the Network Customer

There is no limitation upon a Network Customer's use of the Eversource Transmission System at any particular interface to integrate the Network Customer's Network Resources (or substitute economy purchases) with its Network Loads. However, a Network Customer's use of Eversource's total interface capacity with other transmission systems may not exceed the Network Customer's Load.

15. Additional Study Procedures For Local Network Service Requests

15.1 Disbursement Methodology for Late Study Penalties See Attachment ES-D to Schedule 21-ES

16. Rates and Charges

The Network Customer shall pay Eversource for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following:

16.1 Rates and Charges

Rates for Local Network Service shall be determined as set forth in Schedule ES-4 on the basis of estimated costs for each Service Year until the actual costs for such Service Year are determined. Thereafter, payments made on such estimated costs shall be recalculated based on actual data for that Service Year, and an appropriate billing adjustment shall be made pursuant to Section 3 of this Local Service Schedule.

16.2 Eligible Customers Taking Service Under the ISO Tariff

Any Eligible Customer taking Regional Network Service under the ISO Tariff in a Designated State or Area shall pay to Eversource Service the customer's Category B Load Ratio Share of the Formula Requirements as calculated in Schedule ES-4, Appendix B for such Designated State or Area**.** Eversource Service shall execute a LCRA under this Local Service Schedule, in the form set forth in Attachment ES-E, to recover such charges from such customer. Eversource Service shall not bill any such customer any such costs until (1) such LCRA has been executed with the

Eligible Customer, or (2) an unexecuted LCRA has been permitted to be made effective **by** the Commission.

16.3 Listing of Localized Facilities by Designated State or Area:

(a) Connecticut:
Bethel to Norwalk Project
Middletown to Norwalk Project
Glenbrook Cables Project
Greater Springfield Reliability Project (Connecticut portion)

(b) Massachusetts:
Greater Springfield Reliability Project (Massachusetts portion)

16.4 **Monthly Demand Charge**
The Network Customer shall pay monthly Demand Charges, which shall be determined by multiplying its Category A Load Ratio Share times one twelfth (1/12) of the Formula Requirements in Schedule ES-4, Appendix A, and by multiplying its Category B Load Ratio Share for the Designated State or Area times one twelfth (1/12) of the Formula Requirements in Schedule ES-4, Appendix B for the Localized Facilities that are in such Designated State or Area.

16.5 **Determination of Network Customer's Monthly Network Load**
The Network Customer's Monthly Category A Network Load is its hourly load (including its designated Network Load not physically interconnected with Eversource under Schedule 21) coincident with Eversource’s Monthly Transmission System Peak.

The Network Customer’s Monthly Category B Load for a Designated State **or** Area for a Localized Facility is its hourly load in such Designated State or Area coincident with the monthly transmission system peak load for such Designated State or Area.

For Localized Facilities for which the Designated State or Area is identified as “Connecticut” in Section 16.3(a) of this Schedule 21-ES, the customer’s hourly load shall be all of the customer’s

Regional Network Load in Connecticut, and the monthly transmission system peak load shall be all Regional Network Load in Connecticut.

For Localized Facilities for which the Designated State or Area is identified as "Massachusetts" in Section 16.3(b) of this Schedule 21-ES, the customer's hourly load shall be all of the customer's Regional Network Load in Massachusetts, and the monthly transmission system peak load shall be all Regional Network Load in Massachusetts; provided, that the customer's monthly load and the monthly transmission system peak load shall exclude the load of generators taking RNS for the delivery of offline station service.

16.6 **Determination of Eversource's Monthly Transmission System Load**

Eversource's Monthly Transmission System Category A Load is Eversource's Monthly Transmission System Peak minus the coincident peak usage of all Firm Point-To-Point Transmission Service customers pursuant to this Local Service Schedule plus the Reserved Capacity of all Firm Point-To-Point Transmission Service customers.[1]

Eversource's Monthly Transmission System Category B Load for the Designated State or Area for a **Localized** Facility is the monthly transmission system peak load for such Designated State or Area.[1]

For Localized Facilities for which the Designated State or Area is identified as "Connecticut" in Section 16.3(a) of this Schedule 21-ES, the monthly transmission system peak load shall be all Regional Network Load in Connecticut.

For Localized Facilities for which the Designated State or Area is identified as "Massachusetts" in Section 16.3(b) of this Schedule 21-ES, the monthly transmission system peak load shall be all Regional Network Load in Massachusetts; provided, that the monthly transmission system peak load shall exclude the load of generators taking RNS for the delivery of offline station service.

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1 Excludes MWs associated with lump sum payment transactions identified in footnote 2.

17. Operating Arrangements

17.1 Operation under the Network Operating Agreement

The Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Network Operating Agreement.

17.2 Network Operating Agreement

The terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Part III of the Tariff shall be specified in the Network Operating Agreement. The Network Operating Agreement shall provide for the Parties to (i) operate and maintain equipment necessary for integrating the Network Customer within the Eversource Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between Eversource and the Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside the Eversource Transmission System, interchange schedules, unit outputs for redispatch, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted loads and resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of Part III of the Tariff, including scheduling protocols. The Network Operating Agreement will recognize that the Network Customer shall either (i) operate as a Control Area under applicable guidelines of the North American Electric Reliability Council (NERC) and the Northeast Power Coordinating Council (NPCC), (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with Eversource, or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies NERC and NPCC requirements. Eversource shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services. The Network Operating Agreement is included in Attachment ES-G.

SCHEDULE ES-1

SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by Eversource (if Eversource is the Control Area operator) or indirectly by Eversource making arrangements with the New England System Operator that performs this service for the Eversource Transmission System. The Transmission Customer must purchase this service from Eversource or the New England System Operator. The charges for Scheduling, System Control and Dispatch Service are to be based on the rates set forth below. To the extent the New England System Operator performs this service for Eversource, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to Eversource by that New England System Operator.

Each Point-To-Point Transmission Customer under this Local Service Schedule will be charged for Transmission Scheduling, System Control and Dispatch Services for the total Reserved Capacity specified in each reservation for Point-To-Point Transmission Service made under this Local Service Schedule at the rates set forth in Appendix A of this Schedule ES-1. In the event that a Transmission Customer utilizes transmission capacity without a reservation or exceeds its capacity reservation at any Point of Receipt or Point of Delivery, the Transmission Customer **shall** pay for its actual use of such excess capacity in addition to any Reserved Capacity. The charge for such excess use of capacity shall be determined by multiplying the sum of the actual use in excess of its capacity reservation times the hourly non-firm rate posted on Eversource's OASIS including ancillary services provided pursuant to Schedule ES-1 hereto.

Each Network Customer under this Local Service Schedule will be charged a monthly Transmission Scheduling, System Control and Dispatch Service Demand Charge, which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of the Formula Requirements specified in Appendix B of this Schedule ES-1.

Each Transmission Customer with generation within the New England Control Area shall be required also to provide for Scheduling, System Control and Dispatch Service for that generation. It is anticipated that the Transmission Customer will obtain these services from the ISO. Eversource will make available

Generation Scheduling, System Control and Dispatch Service at the rates set forth in Appendix C of this Schedule ES-1.

Each Transmission Customer with generation located outside of the New England Control Area shall be required to provide for Scheduling, System Control and Dispatching Service for that generation. It is anticipated that the Transmission Customer will obtain these services by contracting for these services from the provider of these services within the Control Area where the generation is located.

Eversource shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Schedule ES-1 in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE ES-1

Appendix A

POINT-TO-POINT TRANSMISSION RATE

Eversource's Formula Rate for Point-To-Point Transmission Scheduling, System Control and Dispatch Service ("Formula Rate") is an annual rate determined from the following formula.

Formula Rate$_i$ = (A_{i-1} – B_{i-1}) C_{i-1} WHERE:

- i equals the calendar year during which service is being rendered ("Service Year").

- A_{i-1} is the Annual Control Center Expenses (expressed in dollars) of Eversource for the calendar year prior to the Service Year. The Annual Control Center Expenses are determined pursuant to the formula specified in Exhibit 1 to this Appendix A of Schedule ES-1.

- B_{i-1} is the actual transmission scheduling, system control and dispatch revenues (expressed in dollars) provided from the provision of transmission services to others. The actual transmission scheduling and dispatch revenues shall be those recorded on the books of each of the companies comprising Eversource hereunder in FERC Account No. 456.1 pertaining to Transmission of Electricity for Others and such other applicable FERC accounts for the calendar year prior to the Service Year.

- C_{i-1} is the average Eversource Monthly Transmission System Category A Load (expressed in kilowatts).

SCHEDULE ES-1

Appendix A

Exhibit 1

DETERMINATION OF ANNUAL CONTROL CENTER EXPENSES

The rate formula for determination of the annual control center expenses revenue requirements for each of the companies comprising Eversource hereunder is determined as follows:

A. ANNUAL CONTROL CENTER EXPENSES

Eversource's System Control and Load Dispatching Expense, for the calendar year prior to the Service Year, as recorded in FERC Account 561.1-561.4 and the revenue requirement calculation for the CL&P Dispatch Center Plant as described in Appendix A, Exhibit 2.

SCHEDULE ES-1

APPENDIX A

EXHIBIT 2

CL&P DISPATCH CENTER REVENUE REQUIREMENT

This exhibit calculates the CL&P Dispatch Center Revenue Requirement. The CL&P Dispatch Center Revenue Requirement for use during a calendar year shall be based on CL&P's costs for the immediately preceding calendar year.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section I. of the ISO-NE Transmission, Markets and Services Tariff and as used in this exhibit have the following definitions:

<u>Dispatch Center</u> means CL&P's CONVEX dispatch center.

<u>Dispatch Center Plant</u> shall equal CL&P's year-end gross plant balances used for CL&P's Dispatch Center as recorded in FERC Account Nos. 303, 350-359, and 389-399.

<u>Dispatch Center Depreciation Reserve</u> shall equal CL&P's year-end depreciation reserve balance for Dispatch Center Plant as recorded in FERC Account No. 108.

<u>Dispatch Center Accumulated Deferred Income Taxes</u> shall equal the net of CL&P's year-end deferred tax balances for Dispatch Center Plant as recorded in FERC Account Nos. 281-283 and 190.

II. CALCULATION OF TOTAL DISPATCH CENTER REVENUE REQUIREMENT

The Dispatch Center Revenue Requirement shall equal the sum of (A) Dispatch Center Return and Associated Income Taxes, (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Amortization of Investment Tax Credits, and (D) Dispatch Center Municipal Tax Expense; provided, that during the period January 1, 2008 through December 31, 2008, the Dispatch Center Revenue Requirement shall equal the product of (i) the number of months (or fractions thereof) remaining in 2007 on and after the date upon which the CONVEX Agreements are permitted to be made effective by FERC, divided by 12 and (ii) the sum of (A) Dispatch Center Return and Associated Income Taxes, (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Amortization of Investment Tax Credits, and (D) Dispatch Center Municipal Tax Expense. "CONVEX Agreements" refers to the agreements between The

Connecticut Light & Power Company and various entities relating to the operation of the Dispatch Center and filed with FERC contemporaneously with the filing of this Exhibit 2.

A. Dispatch Center Return and Associated Income Taxes shall equal the product of the Dispatch Center Investment Base and the Cost of Capital Rate.

1. Dispatch Center Investment Base

The Dispatch Center Investment Base will be the year-end balances of: (a) Dispatch Center Plant, less (b) Dispatch Center Depreciation Reserve, less (c) Dispatch Center Accumulated Deferred Income Taxes.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) the Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon CL&P's capital structure at the end of each year and will equal the sum of (i),(ii), and (iii) below.

(i) The long-term debt component, which equals the product of the year-end balance of CL&P's first mortgage bonds and pollution control notes adjusted for premiums, discounts, debt expense and losses on reacquired debt and the ratio of the long term debt to CL&P's total capital.

(ii) The preferred stock component, which equals the product of the year-end balance of CL&P's preferred stock adjusted for premiums, discounts and unamortized issue expense and the ratio of the preferred stock to CL&P's total capital.

(iii) The common equity component, which equals the product of 10.3% and the ratio of the common equity to CL&P's total capital.

(b and c) Federal and State Income Taxes shall be computed as follows:

A x B x C

where:

A = Dispatch Center Investment Base

B = Cost of equity capital (the sum of the preferred stock component and common equity component)

C = TE / (1-TE), where TE is the effective combined federal and state statutory income tax rates in effect at the applicable time.

B. Dispatch Center Depreciation Expense shall equal CL&P's Dispatch Center depreciation expense as recorded in FERC Account No. 403.

C. Dispatch Center Amortization of Investment Tax Credits shall equal CL&P's Dispatch Center amortization of investment tax credits as recorded in FERC Account No. 411.4.

D. Dispatch Center Municipal Tax Expense shall equal CL&P's Dispatch Center municipal tax expense as recorded in FERC Account Nos. 408.1 and 409.1.

SCHEDULE ES-1

Appendix B

NETWORK TRANSMISSION FORMULA REQUIREMENTS

Eversource’s formula requirements for Network Transmission Scheduling, System Control and Dispatch Service is determined from the following formula.

Formula $\text{Requirements}_i = (A_{i\text{-}1} - B_{i\text{-}1})$

WHERE:

- i equals the calendar year during which service is being rendered ("Service Year").

- $A_{i\text{-}1}$ is the Annual Control Center Expenses (expressed in dollars) of Eversource for the calendar year prior to the Service Year. The Annual Control Center Expenses are determined pursuant to the formula specified in Exhibit 1 to this Appendix B of Schedule ES-1.

- $B_{i\text{-}1}$ is the actual transmission scheduling, system control and dispatch revenues (expressed in dollars) provided from the provision of transmission services to others. The actual transmission scheduling, system control and dispatch revenues shall be those recorded on the books of each of the companies comprising Eversource hereunder in FERC Account No. 456.1 pertaining to Transmission of Electricity for Others and such other applicable FERC Account for the calendar year prior to the Service Year.

SCHEDULE ES-1

APPENDIX B

EXHIBIT 1

DETERMINATION OF ANNUAL CONTROL CENTER EXPENSES

The rate formula for determination of the annual control center expenses for each of the companies comprising Eversource hereunder is determined as follows:

A. ANNUAL CONTROL CENTER EXPENSES

Eversource's System Control and Load Dispatching Expense), for the calendar year prior to the Service Year as recorded in FERC Account 561.1-561.4 and the revenue requirement calculation for the CL&P Dispatch Center Plant as described in Appendix B, Exhibit 2.

SCHEDULE ES-1

APPENDIX B

EXHIBIT 2

CL&P DISPATCH CENTER REVENUE REQUIREMENT

This exhibit calculates the CL&P Dispatch Center Revenue Requirement. The CL&P Dispatch Center Revenue Requirement for use during a calendar year shall be based on CL&P's costs for the immediately preceding calendar year.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section I. of the ISO-NE Transmission, Markets and Services Tariff and as used in this exhibit have the following definitions:

Dispatch Center means CL&P's CONVEX dispatch center.

Dispatch Center Plant shall equal CL&P's year-end gross plant balances used for CL&P's Dispatch Center as recorded in FERC Account Nos. 303, 350-359, and 389-399.

Dispatch Center Depreciation Reserve shall equal CL&P's year-end depreciation reserve balance for Dispatch Center Plant as recorded in FERC Account No. 108.

Dispatch Center Accumulated Deferred Income Taxes shall equal the net of CL&P's year-end deferred tax balances for Dispatch Center Plant as recorded in FERC Account Nos. 281-283 and 190.

II. CALCULATION OF TOTAL DISPATCH CENTER REVENUE REQUIREMENT

The Dispatch Center Revenue Requirement shall equal the sum of (A) Dispatch Center Return and Associated Income Taxes, (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Amortization of Investment Tax Credits, and (D) Dispatch Center Municipal Tax Expense; provided, that during the period January 1, 2008 through December 31, 2008, the Dispatch Center Revenue Requirement shall equal the product of (i) the number of months (or fractions thereof) remaining in 2007 on and after the date upon which the CONVEX Agreements are permitted to be made effective by FERC, divided by 12 and (ii) the sum of (A) Dispatch Center Return and Associated Income Taxes, (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Amortization of Investment Tax Credits, and (D) Dispatch Center Municipal Tax Expense. "CONVEX Agreements" refers to the agreements between The

Connecticut Light & Power Company and various entities relating to the operation of the Dispatch Center and filed with FERC contemporaneously with the filing of this Exhibit 2.

A. Dispatch Center Return and Associated Income Taxes shall equal the product of the Dispatch Center Investment Base and the Cost of Capital Rate.

1. Dispatch Center Investment Base

The Dispatch Center Investment Base will be the year-end balances of: (a) Dispatch Center Plant, less (b) Dispatch Center Depreciation Reserve, less (c) Dispatch Center Accumulated Deferred Income Taxes.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) the Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon CL&P's capital structure at the end of each year and will equal the sum of (i),(ii), and (iii) below.

(i) The long-term debt component, which equals the product of the year-end balance of CL&P's first mortgage bonds and pollution control notes adjusted for premiums, discounts, debt expense and losses on reacquired debt and the ratio of the long term debt to CL&P's total capital.

(ii) The preferred stock component, which equals the product of the year-end balance of CL&P's preferred stock adjusted for premiums, discounts and unamortized issue expense and the ratio of the preferred stock to CL&P's total capital.

(iii) The common equity component, which equals the product of 10.3% and the ratio of the common equity to CL&P's total capital.

(b and c) Federal and State Income Taxes shall be computed as follows:

A x B x C

where:

A = Dispatch Center Investment Base

B = Cost of equity capital (the sum of the preferred stock component and common equity component)

C = TE / (1-TE), where TE is the effective combined federal and state statutory income tax rates in effect at the applicable time.

B. Dispatch Center Depreciation Expense shall equal CL&P's Dispatch Center depreciation expense as recorded in FERC Account No. 403.

C. Dispatch Center Amortization of Investment Tax Credits shall equal CL&P's Dispatch Center amortization of investment tax credits as recorded in FERC Account No. 411.4.

D. Dispatch Center Municipal Tax Expense shall equal CL&P's Dispatch Center municipal tax expense as recorded in FERC Account Nos. 408.1 and 409.1.

SCHEDULE ES-1

Appendix C

GENERATION RATES

Eversource's Formula Rate for Generation Scheduling, System Control and Dispatch Service ("Formula Rate") shall be calculated using the Point-to-Point Formula Rate for Transmission Scheduling, System Control, and Dispatch Service in Appendix A of Schedule ES-1.

SCHEDULE ES-2
FIRM POINT-TO-POINT SERVICE

I. Each month, Eversource Service shall bill the Transmission Customer for Long-Term Firm and Short-Term Firm Transmission Service and the Transmission Customer shall be obligated to pay Eversource the charges as set forth in this Schedule ES-2, as applicable.

A. TRANSMISSION CHARGES

1. Determination of Transmission Charges

The Transmission Charges will provide for recovery of the costs of the transmission facilities ofEversource. The Category A Transmission Charges for each month will equal the sum of the Category A Charges for each monthly (or longer term), weekly or daily transaction during such month. In the event that a Transmission Customer utilizes transmission capacity without a reservation or exceeds its capacity reservation at any Point of Receipt or Point of Delivery, the Transmission Customer **shall** pay for its actual use of such excess capacity in addition to the charges for each monthly, weekly or daily transactions during such month. The charge for such excess use of capacity shall be determined by multiplying the actual hourly use in excess of its capacity reservation times the applicable Category A on-peak or off-peak hourly non-firm rate posted on Eversource's OASIS pursuant to Schedule ES-3 including ancillary services provided pursuant to Schedule ES-1 hereto.

The Category A Charge for each monthly (or longer term) transactions will be the product of: (a) Eversource's Category A Formula Rate (expressed in $ per kilowatt-year), divided by twelve (12) months, and (b) the Reserved Capacity set forth for such monthly (or longer term) transaction (expressed in kilowatts).

The Category A Charge for each weekly transaction will be the product of: (a) Eversource's Weekly Category A Short-Term Firm Point-To-Point Transmission Rate (expressed in $ per kilowatt-week), and (b) the Reserved Capacity set forth for such weekly transaction (expressed in kilowatts). Eversource's Weekly Category A Rate is Eversource's Category A Formula Rate for Firm Point-To-Point Transmission Service divided by fifty-two (52) weeks.

The Category A Charge for each daily transaction will be the product of: (a) Eversource's Daily Category A Short-Term Firm Point-To-Point Transmission Rate (expressed in $ per kilowatt-day), and (b) the Reserved Capacity set forth for such daily transaction (expressed in kilowatts). Eversource's Daily Category A Rate is Eversource's Weekly Category A Rate for Short-Term Firm Point-To-Point Transmission Service divided by five (5) days. The total of the Transmission Customer's charges for daily transactions, under an individual reservation, in a seven (7) day period shall not exceed the charges based on the Weekly Category A Rate and the Transmission Customer's maximum Reserved Capacity in the period.

2. Eversource's <u>Formula Rates</u>

Eversource's Formula Rates for Long-Term Firm and Short-Term Firm Point-To-Point Service shall be determined in accordance with the rate formulas specified in Appendix A of this Schedule ES-2.

3. <u>Tax Rates and Taxes</u>

Eversource's Formula Rates set forth in this schedule in effect during a Service Year shall be based on the local, state, and federal tax rates and taxes in effect during the Service Year. If, at any time, additional or new taxes are imposed on Eversource or existing taxes are removed, Eversource's Formula Rate will be appropriately modified and filed with the Commission in accordance with Part 35 of the Commission's regulations.

4. <u>Provision re: Exchanges</u>

With respect to Entitlement Transactions or Energy Transactions or other transactions that involve an exchange, each party to such transaction shall be treated as an individual Transmission Customer under this Local Service Schedule. Accordingly, a separate Schedule ES-2 or other

applicable charge(s) will be calculated for, and a separate bill will be rendered to, each such individual Transmission Customer.

5. Discounts

Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by Eversource must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, Eversource must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

6. Resales

The rates and rules governing charges and discounts in Sections I.A.1 and 5 of this Schedule ES-2 stated above shall not apply to resales of transmission service, compensation for which shall be governed by Schedule 21.

II. In addition to the applicable charges of this Local Service Schedule, and as otherwise specified in the Service Agreement, the Transmission Customer shall pay to Eversource Service each month the following additional charges for Long-Term, and Short-Term Firm Point-To-Point Transmission Service provided during such month.

A. Taxes and Fees Charge

B. Regulatory Expenses Charge

C. Other

A. **TAXES AND FEES CHARGE**

If any governmental authority requires the payment of any fee or assessment or imposes any form of tax with respect to payments made for Long-Term Firm or Short Term Firm Point-To-Point Transmission Service provided under this Local Service Schedule, not specifically provided for in any of the charge or

rate provisions under this Local Service Schedule, including any applicable interest charged on any deficiency assessment made by the taxing authority, together with any further tax on such payments, the obligation to make payment for any such fee, assessment, or tax shall be borne by the Transmission Customer. Eversource will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's regulations.

B. **REGULATORY EXPENSES CHARGE**

Eversource shall have the right to make a Section 205 filing for recovery of regulatory expenses associated with this Local Service Schedule and the Service Agreements.

C. **OTHER**

Eversource shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Schedule ES-2 in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE ES-2

Appendix A

CATEGORY A RATE

FIRM POINT-TO-POINT TRANSMISSION SERVICE

Eversource's Category A Formula Rate for Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service ("Formula Rate") is an annual rate determined from the following formula.

Formula $\text{Rate}_i = (A_i - B_i + C_i - D_i) / E_i$

WHERE:

- i equals the Service Year.

- A is the annual Total Transmission Revenue Requirements (expressed in dollars) as described in Attachment ES-H,

- B is the revenues received (expressed in dollars) from the provision of transmission and other related services, to others as recorded in FERC Accounts 456.1 and 454 to the extent that such transactions are not included in the determination of load (E),[2] minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

- C is the transmission payments (expressed in dollars) to the New England System Operator as recorded in FERC Account 565 in accordance with the Tariff.

- D is the sum of the annual revenues received (expressed in dollars) for the costs associated with the Localized Facilities, minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

- E is the average Eversource Monthly Transmission System Category A Load (expressed in kilowatts).

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[2] Includes amortization of revenues from point-to-point transmission service provided to Consolidated Edison Energy Massachusetts, Inc. and NRG Energy, Inc. under contracts in which customers paid based on single lump sum payment.

SCHEDULE ES-2

[Reserved]

SCHEDULE ES-3
NON-FIRM POINT-TO-POINT SERVICE

I. Eversource shall bill the Transmission Customer for Non-Firm Point-To-Point Transmission Service, and the Transmission Customer shall be obligated to pay Eversource the charges as set forth in this Schedule ES-3 as applicable.

A. **<u>TRANSMISSION CHARGES</u>**

1. <u>General</u>

The Transmission Customer shall pay to Eversource Service each month the Category A Transmission Charges calculated for all of the Transmission Customer’s monthly transactions, weekly transactions, daily transactions and hourly transactions, each as set forth below. In the event that a Transmission Customer utilizes transmission capacity without a reservation or exceeds its capacity reservation at any Point of Receipt or Point of Delivery, the Transmission Customer shall pay for its actual use of such excess capacity in addition to the charges for each monthly, weekly, daily or hourly transactions during such month. The charge for such excess use of capacity shall be determined by multiplying the actual hourly use in excess of its capacity reservation times the applicable Category A on-peak or off-peak hourly non-firm rate posted on Eversource’s OASIS pursuant to this Schedule ES-3 including ancillary services provided pursuant to Schedule ES-1 hereto.

With respect to any wholesale transactions that involve an exchange, each party to such transaction shall be an individual Transmission Customer under this Local Service Schedule. Accordingly, a Transmission Charge, as applicable, will be calculated for, and a separate bill will be rendered to, each such Transmission Customer.

The Category A Transmission Charge for each month applicable to a monthly transaction shall be determined as the product of: (a) the Category A rate posted on Eversource’s Open Access Same-Time Information System ("OASIS") at the time the service is reserved, not to exceed Eversource’s Annual Category A Rate for Non Firm Point-To-Point Transmission Service divided by twelve (12) months and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Reservation for such month (expressed in kilowatts).

The Category A Transmission Charge for each month applicable to weekly transactions shall be the sum of the transmission charges determined for each weekly transaction during such month. The transmission charge for each weekly transaction shall be determined as the product of: (a) the Category A rate posted on Eversource’s OASIS at the time the service is reserved, not to exceed Eversource’s Weekly Category A Firm Point-To-Point Transmission Charge Rate (expressed in $ per kilowatt-week), and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Reservation for such week (expressed in kilowatts). Eversource’s Weekly Category A Rate is Eversource’s Annual Category A Rate for Non-Firm Point-To-Point Transmission Service divided by fifty-two (52) weeks.

The Transmission Charge for each month applicable to daily transactions will be the sum of the transmission charges determined for each daily transaction. The transmission charge for each daily transaction shall be determined as the product of: (a) the rate posted on Eversource’s OASIS at the time the service is reserved, not to exceed Eversource’s Daily Category A Firm Point-To-Point Transmission Charge Rate (expressed in $ per kilowatt-day), and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Reservation for such day (expressed in kilowatts). Eversource’s Daily Category A On-Peak Rate is Eversource’s Weekly Category A Rate for Non-Firm Point-To-Point Transmission Service divided by five (5) days. Eversource’s Daily Category A Off-Peak Rate is Eversource’s Weekly Category A Rate for Non-Firm Point-To-Point Transmission Service divided by seven (7) days. The total of the Transmission Customer’s charges for daily transactions, under an individual Reservation, in a seven (7) day period shall not exceed the charges based on the Weekly Category A Rate and the Transmission Customer’s maximum Reserved Capacity in the period.

The Transmission Charge for each month applicable to hourly transactions will be the sum of the transmission charges determined for each hourly transaction during such month. The transmission charge for each hour of an hourly Transaction shall be determined as the product of: (a) the rate posted on Eversource’s OASIS at the time the service is reserved, not to exceed Eversource’s Daily Category A Firm Point-To-Point Transmission Service Rate divided by sixteen (16) hours (expressed in $ per kilowatt-hour), and (b) the Reserved Capacity as set forth in the Transmission Customer's applicable Reservation for such hour (expressed in kilowatts). Eversource’s Hourly Category A On-Peak Rate is equal to Eversource’s Daily Category A Rate for Non-Firm Transmission Service divided by sixteen (16) hours. Eversource’s Hourly Category A Off-Peak Rate is equal to Eversource’s Daily Category A Rate for Non-Firm Transmission

Service divided by twenty-four (24) hours. The total of the Transmission Customer's charges for hourly transactions, under an individual Reservation, in a twenty-four (24) hour period shall not exceed the charges based on the Daily Category A Rate and the Transmission Customer's maximum Reserved Capacity in the period.

2. Discounts

Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by Eversource must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, Eversource must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

3. Resales

The rates and rules governing charges and discounts in Sections I.A.1 and 2 of this Schedule ES-3 stated above shall not apply to resales of transmission service, compensation for which shall be governed by Schedule 21.

4. Credit to the Transmission Charge

Whenever service provided hereunder is interrupted or curtailed by Eversource, the Local Control Center or the New England System Operator, the Transmission Charges to the Transmission Customer calculated pursuant to Section A, of this Schedule ES-3 shall be credited by an amount equal to the sum of the credits calculated for each hour of interruption or curtailment in service.

The credit to the Transmission Customer for each such hour of interruption or curtailment shall be calculated as the product of (i) the applicable equivalent hourly charge for hourly, daily, weekly, or monthly transactions, and (ii) the kilowatts of service interruption or curtailment during such hour.

5. Eversource's Annual Formula Rate for Non Firm Point-To-Point Transmission Service

Eversource's Annual Formula Rates for Non Firm Point-To-Point Transmission Service shall be expressed in $ per kilowatt-year and shall be determined in accordance with the rate formulas specified in Appendix A of this Schedule ES-3 ("Formula Rates").

6. Tax Rates and Taxes

The Formula Rates set forth in this Schedule ES-3 in effect during a Service Year shall be based on local, state, and federal tax rates and taxes in effect during the Service Year. If, at any time, additional or new taxes are imposed on Eversource or existing taxes are removed, the Formula Rate will be appropriately modified and filed with the Commission in accordance with Part 35 of the Commission's regulations.

II. In addition to the applicable charges of this Local Service Schedule, and as otherwise specified in the Service Agreement, the Transmission Customer shall pay Eversource Service each month the following additional charges for Non-firm Point-To-Point Transmission Service provided during such month.

A. Taxes and Fees Charge

B. Regulatory Expenses Charge

C. Other

A. **TAXES AND FEES CHARGE**

If any governmental authority requires the payment of any fee or assessment or imposes any form of tax with respect to payments made for Non-Firm Point-To-Point Transmission Service provided under this Local Service Schedule, not specifically provided for in any of the charge or rate provisions under this Local Service Schedule, including any applicable interest charged on any deficiency assessment made by the taxing authority, together with any further tax on such payments, the obligation to make payment for such fee, assessment, or tax shall be borne by the Transmission Customer. Eversource will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's regulations.

B. **REGULATORY EXPENSES**

Eversource reserves its rights to make a Section 205 filing for recovery of its costs to administer this Local Service Schedule and the Service Agreements.

C. **OTHER**

Eversource shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Schedule ES-3 in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE ES-3

Appendix A

CATEGORY A RATE

FOR NON-FIRM POINT-TO-POINT SERVICE

Eversource's Category A Formula Rate for Non-Firm Point-To-Point Transmission Service ("Formula Rate") is an annual rate determined from the following formula.

$$\text{Formula Rate}_i = (A_i - B_i + C_i - D_i) / E_i$$

WHERE:

- i equals the Service Year.

- A is the annual Total Transmission Revenue Requirements (expressed in dollars) as described in Attachment ES-H.

- B is the revenues received (expressed in dollars) from the provision of transmission and other related services to others as recorded in FERC Accounts 456.1 and 454 to the extent that such transactions are not included in the determination of load (E),[2] minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

- C is the transmission payments (expressed in dollars) to the New England System Operator as recorded in FERC Account 565 in accordance with the Tariff.

- D is the sum of the annual revenues received (expressed in dollars) for the costs associated with the Localized Facilities, minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

- E is the average Eversource Monthly Transmission System Category A Load (expressed in kilowatts).

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[2] Includes amortization of revenues from point-to-point transmission service provided to Consolidated Edison Energy Massachusetts, Inc. and NRG Energy, Inc. under contracts in which customers paid based on single lump sum payment.

SCHEDULE ES-3[RESERVED]

SCHEDULE ES-4

CHARGE PROVISIONS FOR LOCAL NETWORK SERVICE

I. Network Customers will pay the following demand charges for Local Network Service.

A. **DEMAND CHARGE A**

1. Determination of Demand Charge:
The Demand Charge will be determined in accordance with Section ~~16.3~~16.4 of this Local Service Schedule.

2. Eversource's Annual Transmission Revenue Requirements:
The annual Transmission Revenue Requirements shall be determined in accordance with the formula specified in Appendix A of this Schedule ES-4 ("Formula Requirements").

B. **DEMAND CHARGE B**

1. Determination of Demand Charge
The Demand Charge will be determined in accordance with Section ~~16.3~~16.4 of this Local Service Schedule.

2. Eversource Annual Transmission Revenue Requirements:
The annual Transmission Revenue Requirements for each Localized Facility of a Designated State or Area shall be determined in accordance with the formula specified in Appendix B of this Schedule ES-4 ("Formula Requirements").

C. TAX RATES AND TAXES

The Formula Requirements set forth in this Schedule ES-4 in effect during a Service Year shall be based on local, state, and federal tax rates and taxes in effect during the Service Year. If, at any time, additional or new taxes are imposed on Eversource or existing taxes are removed, the Formula Requirements will be appropriately modified and filed with the Commission in accordance with Part 35 of the Commission's regulations.

II. In addition to the applicable charges of this Local Service Schedule, and as otherwise specified in the Service Agreement, the Transmission Customer shall pay to Eversource Service each month the following additional charges for Local Network Service provided during such month.

A. Taxes and Fees Charge

B. Regulatory Expenses Charge

C. Other

A. **TAXES AND FEES CHARGE**

If any governmental authority requires the payment of any fee or assessment or imposes any form of tax with respect to payments made for service provided under this Local Service Schedule, not specifically provided for in any of the charge or rate provisions under this Local Service Schedule, including any applicable interest charged on any deficiency assessment by the taxing authority, together with any further tax on such payments, the obligation to make payment for any such fee, assessment, or tax shall be borne by the Transmission Customer. Eversource will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's regulations.

B. **REGULATORY EXPENSES CHARGE**

Eversource shall have the right to make a Section 205 filing for recovery of regulatory expenses associated with this Local Service Schedule and the Service Agreements.

C. **OTHER**

Eversource shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Schedule ES-4 in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE ES-4

Appendix A

NETWORK FORMULA REQUIREMENTS

FOR CATEGORY A COSTS

Eversource's formula requirements for Local Network Service is determined from the following formula.

$$\text{Formula Requirements}_i = A_i – B_i + C_i - D_i$$

WHERE:

- $_i$ equals the Service Year.

- A is the annual Total Transmission Revenue Requirements (expressed in dollars) as described in Attachment ES-H.

- B is the revenues received (expressed in dollars) from the provision of transmission and other related services to others as recorded in FERC Accounts 456.1 and 454 to the extent that such transactions are not included in the determination of load,[2] minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

- C is the transmission payments to (expressed in dollars) the New England System Operator as recorded in FERC Accounts 565 in accordance with the Tariff.

- D is the sum of the annual revenues received (expressed in dollars) for the costs associated with Localized Facilities, minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

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2 Includes amortization of revenues from point-to-point transmission service provided to Consolidated Edison Energy Massachusetts, Inc. and NRG Energy, Inc. under contracts in which customers paid based on single lump sum payment.

SCHEDULE ES-4

Appendix B

NETWORK FORMULA REQUIREMENTS

FOR CATEGORY B COSTS

Eversource's formula requirements for Local Network Service and for Eligible Customers taking Regional Network Service under this Tariff in a Designated State or Area of a Localized Facility, is determined from the following formula, and separately determined for each Designated State or Area of a Localized Facility.

$$\text{Formula Requirements}_i = D_i$$

WHERE:

- $_i$ equals the Service Year.

- D is the annual Localized Transmission Revenue Requirements (expressed in dollars) of the Localized Facilities of Eversource for a Designated State or Area of a Localized Facility, as described in Attachment ES-I.

ATTACHMENT ES-C

AVAILABLE TRANSFER CAPABILITY METHODOLOGY

TABLE OF CONTENTS

1. Introduction

ISO is the regional transmission organization ("RTO"), serving the New England Control Area. ISO is responsible for the development, oversight, and fair administration of New England's wholesale market, management of the bulk electric power system and wholesale markets' planning processes. The ISO serves as the Balancing Authority for the New England Control Area. The New England Control Area is interconnected to three neighboring Balancing Authority Areas ("BAA"): New Brunswick System Operator Area ("NBSO Area"), New York Independent System Operator Area ("NYISO Area"), and Hydro-Quebec TransEnergie Area ("HQTE Area").

As part of its RTO responsibilities, the ISO is registered with the North American Electric Reliability Corporation ("NERC") as several functional model entities that have responsibilities related to the calculation of ATC as defined in the following NERC Standards: MOD-001 – Available Transmission System Capability ("MOD-001"), MOD-004 – Capacity Benefit Margin ("MOD-004"), and MOD-008 – Transmission Reliability Margin Calculation Methodology ("MOD-008"). The extent of those responsibilities is based on various Commission approved transmission operating agreements and the provisions of the ISO New England Operating Documents.

While the ISO is the Transmission Service Provider for Regional Network Service ("Regional Transmission Service") associated with Pool Transmission Facilities, the Participating Transmission Owners ("PTOs") provide local transmission service over Non-Pool Transmission Facilities within the RTO footprint and are responsible for calculating TTC and ATC associated with Local Transmission Service provided under Schedule 21 pursuant to the Transmission Operating Agreement ("TOA"). Pursuant to CFR § 37.6(b)[1] of the FERC Regulations Transmission Provider's are obligated to calculate and post TTC and ATC for each Posted Path. The ISO is not responsible for the calculation of these values.

Pursuant to the terms of the Transmission Operating Agreement executed between the companies comprising Eversource hereunder as Participating Transmission Owners ("PTOs") and ISO, Eversource is a Transmission Service Provider and calculates TTC and ATC for certain Local Facilities over which Point-to-Point transmission service is provided under Schedule 21-ES of the ISO Open Access Transmission Tariff ("ISO OATT").

[1] §37.6(b) Posting transfer capability. The available transfer capability on the Transmission Provider's system (ATC) and the total transfer capability (TTC) of that system shall be calculated and posted for each Posted Path as set out in this section.

Posted Path is defined as any control area to control area interconnection; any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a customer requests to have ATC or TTC posted. For this last category, the posting must continue for 180 days and thereafter until 180 days have elapsed from the most recent request for service over the requested path. For purposes of this definition, an hour includes any part of any hour during which service was denied, curtailed or interrupted (§37.6(b)(1)(i)).

Non-PTF facilities are primarily radial paths that provide transmission service directly to interconnected generators. It is possible, in the future that a particular path may interconnect more nameplate capacity generation than the path's TTC. However, for Eversource's Non-PTF modeled by the ISO or the Local Control Center ("LCC"), the ISO or the LCC will only dispatch an amount of generation interconnected to such path so as not to incur a reliability or stability violation on the subject path consistent with ISO's economic, security constrained dispatch methodology.

Eversource does not currently have any Posted Paths based on the above definition. However, if Eversource does have any Posted Path(s) in the future, Eversource will calculate TTC using NERC Standard MOD-029-1 Rated System Path Methodology as outlined below.

1.1 Scope of Document

The scope of this document is limited to those functions performed or utilized by Eversource as the Transmission Provider of Schedule 21-ES Local Point-to Point transmission service over Non-PTF pursuant to the PTOs' Transmission Operating Agreement and the ISO OATT:

- Total Transfer Capability (TTC) methodology
- Available Transfer Capability (ATC) methodology
- Existing Transmission Commitment (ETC)
- Use of Rollover Rights (ROR) in the calculation of ETC

As explained in Section 2, TTC and ATC are required to be calculated only for certain non-PTF internal Posted Paths over which Local Point-to-Point transmission service is provided under Schedule 21-ES. TTC and ATC is not calculated by Eversource for Local Network Service because ISO employs a market model for economic, security constrained dispatch of generation, and Eversource does not require advance reservation for such network service.

2. Transmission Service in the New England Markets

Since the inception of the OATT for New England, the process by which generation located inside New England supplies energy to the bulk electric system has differed from the Commission's pro forma OATT. The fundamental difference is that internal generation is dispatched in an economic, security constrained manner by the ISO rather than utilizing a system of physical rights, advance reservations and point-to-point transmission service. Through this process, internal generation provides offers that are utilized by the ISO in the Real-Time Energy Market dispatch software. This process provides the least-cost dispatch to satisfy Real-Time load on the system.

In addition to offers from generation within New England, entities may submit External Transactions to move energy into the ISO Area, the New England Control Area, out of the New England Control Area, or through the New England Control Area. The Real-Time Energy Market clears these External Transactions based on forecast Locational Marginal Pricing (LMPs) and the transfer capability of the associated external interfaces. With those External Transactions in place, the Real-Time Energy Market dispatches internal generation in an economic, security constrained manner to meet Real-Time load within the region.

This process for submitting External Transactions into the New England Real-Time Energy Market does not require an advance physical reservation for use of the PTF. In the event that the net of the economic External Transactions is greater than the transfer capability of the associated external interface, the External Transactions selected to flow are selected based on the rules specified in the Tariff. For any External Transactions that are confirmed to flow in Real-Time based on the economics of the system, a transmission reservation for RNS and Through or Out Service is created after-the-fact to satisfy the transparency needs of the market.

The process described above is applicable to the PTF within the ISO Area, and non-PTF Local Facilities where utilized for Local Network Service by generation or load. However, Eversource owns Local Facilities over which an advance transmission service reservation for firm or non-firm transmission service may be required. On those Local Facilities, the market participant may obtain a transmission service reservation from Eversource under Schedule 21-ES prior to delivery of energy into the New England Wholesale Market. This document addresses the calculation of ATC and TTC for these non-PTF internal paths.

3. Eversource **Total Transfer Capability (TTC)**

The Total Transfer Capability (TTC) is the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions. TTC for Schedule 21-ES is calculated using NERC Standard MOD-029-1 Rated System Path Methodology and posted on Eversource's OASIS site.

Eversource will calculate and post TTC on its OASIS site for all non-PTF Posted Paths that are eligible for Point-to-Point transmission service reservations. The TTC on Eversource's non-PTF Local Facilities that are eligible for Local Point-to-Point transmission service reservations are relatively static values. Eversource thus calculate the TTC for Non-PTF Posted Paths that may require Local Point-to-Point Local Point-to-Point transmission reservations on its OASIS provider page according to NAESB Standards.

4. Capacity Benefit Market (CBM)

CBM is defined as the amount of firm transmission transfer capability set aside by a TSP for use by the Load Serving Entities. The ISO does not set aside any CBM for use by the Load Serving Entities, because of the New England approach to capacity planning requirements in the ISO New England Operating Documents. Load Serving Entities operating within the New England Control Area are required to arrange for their Capacity Requirements prior to the beginning of any given month in accordance with ISO Tariff, Section III.13.7.3.1 (Calculation of Capacity Requirement and Capacity Load Obligation). Load Serving Entities do not utilize CBM to ensure that their capacity needs are met; therefore, CBM is not applicable within the New England market design. Accordingly, for purposes of Eversource's ATC calculation and because CBM for the New England Control Area is set to zero (0), Eversource utilizes a zero (0) CBM value.

Existing Transmission Commitments, Firm (ETC_F)

The ETC_F are those confirmed Firm transmission reservations (PTP_F) plus any rollover rights for Firm transmission reservations (ROR_F) that have been exercised. There are no allowances necessary for Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$),

grandfathered Transmission Service (GF_F) and other service(s), contract(s) or agreement(s) (OS_F) to be considered in the ETC_F calculation.

Existing Transmission Commitments, Non-Firm(ETC_{NF})

The (ETC_{NF}) are those confirmed Non-Firm transmission reservations (PTP_{NF}). There are no allowances necessary for Non-Firm Network Integration Transmission Service ($NITS_{NF}$), Non-Firm grandfathered Transmission Service (GF_{NF}) or other service(s), contract(s) or agreement(s) (OS_{NF}).

5. Transmission Reliability Margin (TRM)

TRM is the amount of transmission transfer capability set aside to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. It is used only for external interfaces under the New England market design. Eversource does not have any external interfaces, and therefore TRM for Eversource's non-PTF facilities is zero.

6. Calculation of ATC for Eversource's Local Facilities - General Description:

NERC Standards MOD-001-1 – Available Transmission System Capability and MOD-029-1 – Rated System Path Methodology define the required items to be identified when describing a transmission provider's ATC methodology. As a practical matter, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

Common practice is not to calculate or post firm and non-firm ATC values for the non-PTF assets described above, as ATC is positive and listed as 9999. Transmission customers are not restricted from reserving firm or non-firm transmission service on non-PTF facilities.

As Real-Time approaches, the ISO utilizes the Real-Time energy market rules to determine which of the submitted energy transactions will be scheduled in the coming hour. Basically, the ATC of the non-PTF assets in the New England market is almost always positive. With this simplified version of ATC, there is no detailed algorithm to be described or posted. Thus, for those non-PTF facilities that serve as a path for Eversource's Schedule 21-ES Point-to-Point Transmission Customers, Eversource has posted the ATC as 9999, consistent with industry practice. ATC on these paths varies depending on the time of day.

However, it is posted with an ATC of "9999" to reflect the fact that there are no restrictions on these paths for commercial transactions.

6.1 Calculation of Schedule 21-ES Firm ATC (ATC_F)

6.1.1 Calculation of ATC_F in the Planning Horizon (PH)

For purposes of this Attachment C PH is any period before the Operating Horizon.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for TRM, CBM, ETC_F, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM are zero. Firm Transmission Service under Schedule 21-ES that is available in the Planning Horizon (PH) includes: Yearly, Monthly, Weekly, and Daily. $Postbacks_F$ and $counterflows_F$ of Schedule 21-ES transmission reservations are not considered in the ATC calculation. Therefore, ATC_F in the PH is equal to the TTC minus ETC_F

6.1.2 Calculation of ATC_F in the Schedule 21-ES Operating Horizon (OH)

For purposes of this Attachment C OH is noon eastern prevailing time each day. At that time, the OH spans from noon through midnight of the next day for a total of 36 hours. As time progresses, the total hours remaining in the OH decreases until noon the following day when the OH is once again reset to 36 hours.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for ETC_F, CBM, TRM, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM is zero. Daily Firm Transmission Service under Schedule 21-ES is the only firm service offered in the Operating Horizon (OH). $Postbacks_F$ and $counterflows_F$ of Schedule 21-ES transmission reservations are not considered in the ATC_F calculation. Therefore, ATC_F in the OH is equal to the TTC minus ETC_F.

6.1.3 Because Firm Schedule 21-ES transmission service is not offered in the Scheduling Horizon (SH): ATC_F in the SH is zero.

6.2 Calculation of Schedule 21-ES Non-Firm ATC (ATC_{NF})

6.2.1 Calculation of ATC_{NF} in the PH

ATC_{NF} is the capability for Non-Firm transmission reservations that remain after allowing for ETC_F, ETC_{NF}, scheduled CBM (CBM_S), unreleased TRM (TRM_U), Non-Firm Postbacks ($Postbacks_{NF}$) and Non-Firm counterflows ($counterflows_{NF}$).

As discussed above, the TRM and CBM for Schedule 21-ES are zero. Non-Firm ATC available in the PH includes: Monthly, Weekly, Daily and Hourly. TRM_U, $Postbacks_{NF}$ and $counterflows_{NF}$ of Schedule 21-ES transmission reservations are not considered in this calculation. Therefore, ATC_{NF} in the PH is equal to the TTC minus ETC_F and ETC_{NF} .

6.2.2 Calculation of ATC_{NF} in the OH

ATC_{NF} available in the OH includes: Daily and Hourly.

As discussed above TRM and CBM for Schedule 21-ES are zero. TRM_U, counterflows and ETC_{NF} are not considered in this calculation. Therefore, ATC_{NF} in the OH is equal to the TTC minus $ETC_{F,}$ plus postbacks of PTP_F in OH as PTP_{NF} ($Postbacks_{NF}$)

6.3 Negative ATC

As stated above, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

As stated above, Eversource's non-PTF facilities are primarily radial paths that provide transmission service to directly interconnected generators. It is possible, in the future, that a particular radial path may interconnect more nameplate capacity generation than the path's TTC. However, due to the ISO's security constrained dispatch methodology, the ISO will only dispatch an amount of generation interconnected to such path so as not to incur a reliability or stability violation on the subject path. Therefore, ATC in the PH, OH and SH may become zero, but will not become negative.

7. Posting of Schedule 21-ES ATC

7.1 Location of ATC Posting

ATC values are posted on Eversource's OASIS site.

7.2 Updates To ATC

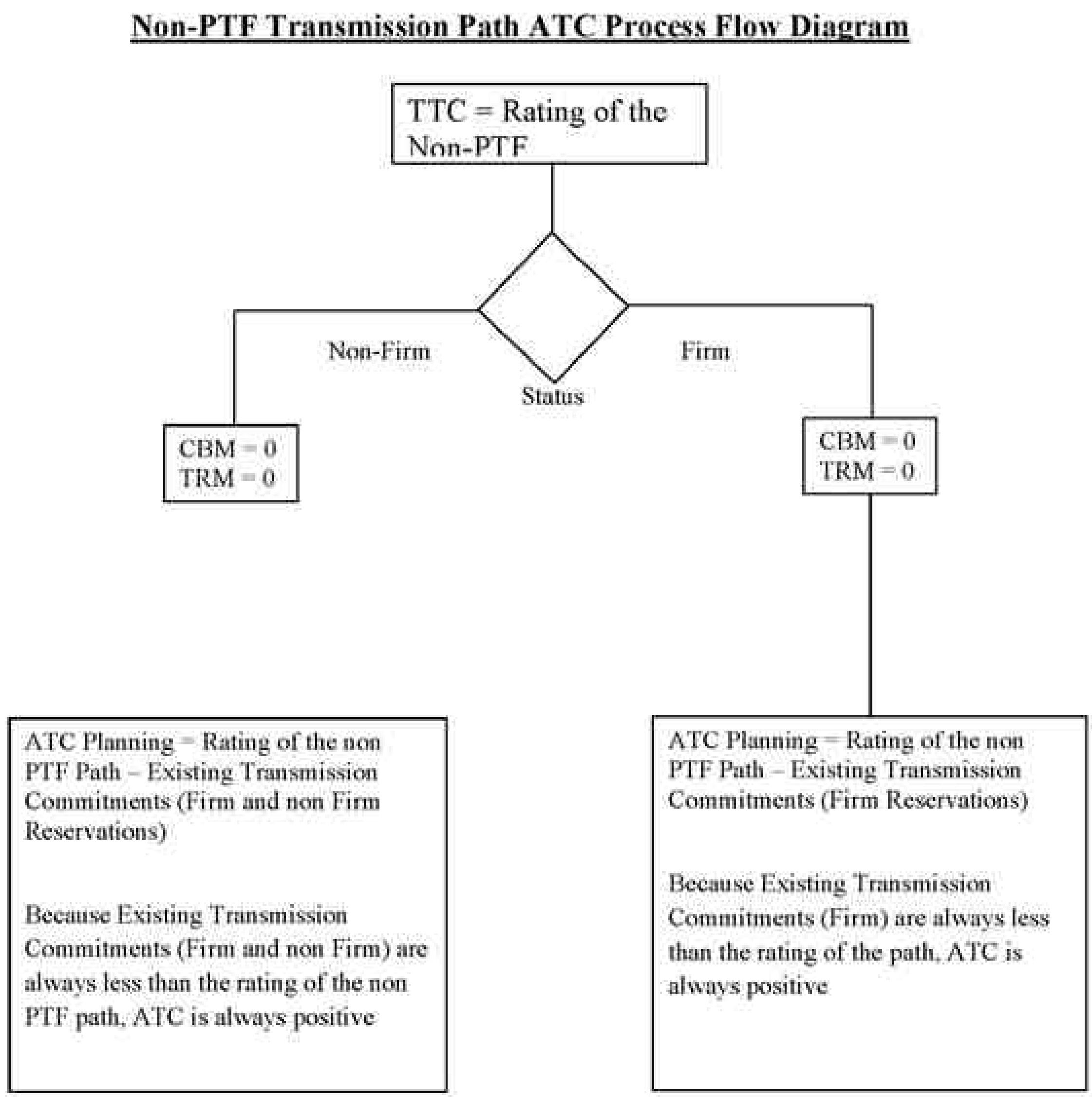
When any of the variables in the ATC equations change, the ATC values are recalculated and immediately posted.

7.3 Coordination of ATC Calculations

Schedule 21-ES non-PTF has no external interfaces. Therefore it is not necessary to coordinate the values.

7.4 Mathematical Algorithms A link to the actual mathematical algorithm for the calculation of ATC for the Eversource non-PTF internal interfaces is located at https://www.eversource.com/Content/docs/default-source/Tranmission/attachment-6.pdf?sfvrsn=0.

8. Process Flow Diagram for ATC Calculation



ATTACHMENT ES-D
PENALTY DISBURSEMENT METHODOLOGY

Late Study Penalties: Penalties paid by the Transmission Provider pursuant to Schedule 21 are referred to as "Late Study Penalties," and therefore subject to distribution to all Transmission Customers that are not affiliated with the Transmission Provider. On the month following the end of each calendar quarter, each Transmission Customer that is not affiliated with the Transmission Provider shall receive, on the relevant monthly invoice, a credit for its share of the Late Study Penalties that were assessed during the applicable calendar quarter. The Transmission Customer's share of the Late Study Penalties (if any) will be determined as follows:

(a) For each quarter, the Transmission Provider will determine: (1) the sum of all Late Study Penalties assessed during the quarter measured in dollars (LSRq), and (2) the sum of all transmission revenue from Transmission Customers that are not affiliated with the Transmission Provider during that quarter, measured in dollars (LSTRq). Where:

LSRq =	Late Study Penalty Revenue in the quarter
LSTRq =	Transmission Revenue from Transmission Customers not affiliated with the Transmission Provider in the quarter

(b) For each quarter, each Transmission Customer that was not affiliated with the Transmission Provider will receive a credit equal to the product of (i) LSRq multiplied by (ii) a fraction derived from dividing the amount of transmission revenue from that Transmission Customer (TC1) during that quarter (measured in dollars), where TC1 is equal to one Transmission Customer, and a denominator equal to LSTRq.

(c) The Transmission Provider shall apply the credit for Late Study Penalties to service that the non-affiliated Transmission Customer takes from the Transmission Provider pursuant to this Schedule 21-ES. Any remaining credit will be refunded to the Transmission Customer.

ATTACHMENT ES-E

LOCALIZED COSTS RESPONSIBILITY **AGREEMENT**

This Localized Costs Responsibility Agreement ("LCRA" or "Agreement"), dated as of _______________________, is entered into by and between the Eversource Energy Service Company ("Eversource Service" or "COMPANY"), acting as agent for [The Connecticut Light and Power Company, Western Massachusetts Electric Company, Public Service Company of New Hampshire], andthe "Transmission Customer".

The Transmission Customer is _____________________________________. The Transmission Customer has been determined to be an Eligible Customer taking Regional Network Service under the Tariff whose load **is located in the** Designated State or Area for a **Localized** Facility listed in **Section** 16.3 **of** Schedule 21-ES of the Tariff**.**

The Transmission Customer agrees to pay its portion of the cost of Localized Facilities in the Designated State or Area in which the Transmission Customer's load is located as provided in the Tariff and in accordance with Commission orders. Billing under this Agreement shall commence on the later of: (1) 0001 hours on _____________________, or (2) such other date as permitted by the Commission.

Charges under this Agreement shall terminate on the earlier of: (1) the date on which the costs of the Localized Facilities in the Designated State or Area in which the Transmission Customer's load is located are fully depreciated; or (2) the date upon which the Transmission Customer no longer takes Regional Network Service under the Tariff in the Designated State or Area in which the Transmission Customer's load is located; provided, that the Transmission Customer shall remain responsible for all final payment obligations. In the event that the Transmission Customer sells or assigns, or transfers its load to another entity ("New Transmission Customer"), the Transmission Customer must provide Eversource Service with at least ninety (90) calendar days advance written notice of the sale, assignment, or transfer.

The Transmission Customer shall remain liable for the performance of all obligations under this Agreement until a new LCRA has been executed between the New Transmission Customer and Eversource Service, or in the case of an unexecuted LCRA, such other date as it has been **permitted to** be made effective by the Commission. No sale or assignment shall **become effective** until the Parties have complied with all Applicable Laws and Regulations required for such sale, assignment, or transfer**.**

Other special provisions (if any)

____.

Any notice or request made to or by any Party regarding this greement shall be made in writing and shall be telecommunicated or delivered either in person, or by prepaid mail (return receipt requested) to the representative of the other Party as indicated below. Such representative and address for notices or requests may be changed from time to time by notice by one Party to the other.

COMPANY:

____

____

____

TRANSMISSION CUSTOMER:

____

____

____

Any exhibits to thisAgreement and the Tariff are incorporated herein and made a part hereof. ThisAgreement may be amended, from time to time, as provided for in Schedule 21-ES of the Tariff.

IN WITNESS WHEREOF, the Parties have caused thisAgreement to be executed by their respective authorized officials as of the date first above written.

EVERSOURCE ENERGY SERVICE COMPANY

By: ___________________________________

Its ________________________

TRANSMISSION CUSTOMER

By**:** _________________________________

Its ___________________________________

ATTACHMENT ES-G

NETWORK OPERATING AGREEMENT

This Network Operating Agreement is an appendix to Schedule 21-ES (this Local Service Schedule) of the OATT and operates as an implementing agreement for Local Network Service under this Local Service Schedule. This Network Operating Agreement is subject to and in accordance with Part III of this Local Service Schedule. All definitions and other terms and conditions of this Local Service Schedule are incorporated herein by reference.

1.0 Definitions:

1.1 Data Acquisition Equipment

Supervisory control and data acquisition ("SCADA"), remote terminal units ("RTUs") to obtain information from a Party's facilities, telephone equipment, leased telephone circuits, fiber optic circuits, and other communications equipment necessary to transmit data to remote locations, and any other equipment or service necessary to provide for the telemetry and control requirements of this Local Service Schedule.

1.2 Data Link

The direct communications link between the Transmission Customer's energy control center and Eversource's designated location(s) that will enable Eversource to receive real time telemetry and data from the Transmission Customer.

1.3 Metering Equipment

High accuracy, solid state kW, kVAR, kWh meters, metering cabinets, metering panels, conduits, cabling, high accuracy current transformers and high accuracy potential transformers, which directly or indirectly provide input to meters or transducers, metering recording devices, telephone circuits, signal or pulse dividers, transducers, pulse accumulators, metering sockets, test switch devices, enclosures, conduits, and any other metering, telemetering or communication equipment necessary to implement the provisions of this Local Service Schedule.

1.4 Protective Equipment

Protective relays, relaying panels, relaying cabinets, circuit breakers, conduits, cabling, current transformers, potential transformers, coupling capacitor voltage transformers, wave traps, transfer trip and

fault recorders, which directly or indirectly provide input to relays, fiber optic communication equipment, power line carrier equipment and telephone circuits, and any other protective equipment necessary to implement the protection provision of this Local Service Schedule.

2.0 Term

The term shall be as provided in the Service Agreement consistent with this Local Service Schedule (including, but not limited to, application procedures, commencement of service, and effect of termination).

3.0 Point(s) Of Interconnection

Local Network Service will be provided by Eversource at the point(s) of interconnection specified in Appendix __, as amended from time to time. Each point of interconnection in this listing shall have a unique identifier, meter location, meter number, metered voltage, terms on meter compensation and designation of current or future year of in service.

4.0 Cogeneration And Small Power Production Facilities

If a Qualifying Facility is located or locates in the future on the System of the Transmission Customer, and the owner or operator of such Qualifying Facility sells the output of such Qualifying Facility to an entity other than the Transmission Customer, the delivery of such Qualifying Facility's power shall be subject to and contingent upon transmission arrangements being established with Eversource prior to commencement of delivery of any such power and energy.

5.0 Character Of Service

Network Transmission Service at the points of interconnection shall be in the form of single phase or balanced three-phase alternating current at a frequency of sixty (60) hertz. The Transmission Customer shall operate and maintain its electric system in a manner that avoids: (i) the generation of harmonic frequencies exceeding the limits established by the latest revision of IEEE-519; (ii) voltage flicker exceeding the limits established by the latest revision of IEEE-141; (iii) negative sequence currents; (iv) voltage or current fluctuations; (v) frequency variations; or (vi) voltage or power factor levels that could adversely affect Eversource’s electrical equipment or facilities or those of its customers, and in a manner that complies with all applicable NERC, NPCC, ISO and Eversource’s operating criteria, rules, regulations, procedures, guidelines and interconnection standards as amended from time to time.

6.0 Continuity Of Service

(a) Eversource and the Transmission Customer shall operate and maintain their respective network systems, in accordance with Good Utility Practice, and in a manner that will allow Eversource to safely and reliably operate the Eversource Transmission System in accordance with this Local Service Schedule, so that either Party shall not unduly burden the other Party; provided, however, that notwithstanding any other provision of this Local Service Schedule, Eversource shall retain the sole responsibility and authority for all operating decisions that could affect the integrity, reliability and security of the Eversource Transmission System.

(b) Eversource shall exercise reasonable care and Due Diligence to ensure Local Network Service hereunder in accordance with Good Utility Practice; provided, however, that Eversource shall not be responsible for any failure to ensure electric power service, nor for interruption, reversal or abnormal voltage of the service, if such failure, interruption, reversal or abnormal voltage is due to a Force Majeure.

7.0 Power Factor

(a) Where Local Network Service provided under this Local Service Schedule is for delivery of power to a load center of the Transmission Customer served from the Eversource Transmission System, the Transmission Customer shall maintain load power factor levels, during both on- and off- peak hours, appropriate to meet the operating requirements of Eversource, and shall follow the ISO standards and practices, as set forth in the Service Agreement.

(b) Where Local Network Service provided under this Local Service Schedule is for delivery of power from a generating facility connected to the Eversource Transmission System, the Transmission Customer shall deliver power at a lagging or leading power factor as set forth in the Service Agreement.

(c) Where Local Network Service provided under this Local Service Schedule is for delivery of power from outside the Eversource Transmission System, the obligation to maintain proper sending and receiving end voltages rests with the Transmission Customer, as set forth in the Service Agreement.

(d) In the event that the power factor levels and reactive supply requirements set forth in the Service Agreement are not maintained by the Transmission Customer, Eversource shall thereupon have the right to take the appropriate corrective action and to charge the Transmission Customer for the costs thereof.

Eversource shall have the right, at any time, unilaterally to make a Section 205 filing with the Commission for the recovery of any such costs.

8.0 Metering

(a) The Transmission Customer shall, at its expense, purchase all necessary metering equipment to accurately account for the electric power being transmitted under this Local Service Schedule. Eversource may require the installation of telemetering equipment for the purposes of billing, power factor measurements and to allow Eversource to maximize economic and reliable operation of its transmission system. Such metering equipment shall meet the specifications and accepted metering practices of Eversource and applicable criteria, rules, standards and operating procedures, or such successor rules and standards. At Eversource's option, communication metering equipment may be installed in order to transmit meter readings to Eversource's designated locations.

(b) Electric power being transmitted under this Local Service Schedule will be measured by meters at all points of interconnection and/or on generating facilities (Network and non-Network Resources) located on and outside the Transmission Customer's system as required by Eversource.

(c) The Transmission Customer shall purchase meters capable of time-differentiated (by hour) measurement of the instantaneous flow in kW and net active power flow in kWh and of reactive power flow. All meters shall compensate for applicable line and/or transformer losses in accordance with Good Utility Practice when measurement is made at any location other than the point of interconnection.

(d) Eversource reserves the right: (i) to determine metering equipment ownership; (ii) to determine the equipment installation at each point of interconnection; (iii) to require the Transmission Customer to install the equipment -- or -- install the equipment with the Transmission Customer supplying without cost to Eversource a suitable place for the installation of such equipment; (iv) to determine other equipment allowed in the metering circuit; (v) to determine metering accuracy requirements; (vi) to determine the responsibilities for operation, maintenance, testing and repair of metering equipment.

(e) Eversource shall have access to metering data, including telephone line access, which may reasonably be required to facilitate measurement and billing under this Local Service Schedule. Eversource may require the Transmission Customer provide, at its expense, a separate dedicated voice grade telephone circuit for Eversource and the Transmission Customer to remotely access each meter.

Metering equipment and data shall be accessible at all reasonable hours for purposes of inspection and reading.

(f) All metering equipment shall be tested in accordance with practices of Eversource, applicable criteria, rules, standards and operating procedures or upon the request by Eversource. If at any time metering equipment fails to register or is determined to be inaccurate, in accordance with Eversource’s practices and applicable criteria, rules, standards and operating procedures, the Transmission Customer shall make the equipment accurate as soon thereafter as practicable, and the meter readings and rate computation for the period of such inaccuracy, insofar as can reasonably be ascertained, shall be adjusted; provided, however, that no adjustment to charges shall be required for any period exceeding two (2) months prior to the date of the test. Representatives of Eversource will be afforded opportunity to witness such tests.

9.0 Network Load

The Transmission Customer shall provide Eversource with the actual hourly Network Load for each calendar month by the seventh day of the following calendar month.

10.0 Data Transfer:

(a) The Transmission Customer shall provide timely, accurate real time information to Eversource in order to facilitate performance of its obligations under this Local Service Schedule.

(b) The selection of real time telemetry and data to be received by Eversource and the Transmission Customer shall be necessary for safety, reliability, security, economics, and/or monitoring of real-time conditions that affect the Eversource Transmission System. This telemetry shall include, but is not limited to, loads, line flows (MW and MVAR), voltages, generator output, and status of substation equipment at any of the Transmission Customer's transmission and generation facilities. To the extent that Eversource or the Transmission Customer requires data that are not available from existing equipment, the Transmission Customer shall, at its expense and at locations designated by Eversource or the Transmission Customer, install any metering equipment, data acquisition equipment, or other equipment and software necessary for the telemetry to be received by Eversource or the Transmission Customer. Eversource shall have the right to inspect equipment and software associated with the data transfer in order to assure conformance with Good Utility Practices.

11.0 Maintenance of Equipment

The Transmission Customer shall, on a regular basis in accordance with practices of Eversource, applicable criteria, rules, standards and operating procedures or at the request of Eversource, and at its expense, test, calibrate, verify and validate the data link, metering equipment, data acquisition equipment, transmission equipment, protective equipment and other equipment or software used to implement the provisions of this Local Service Schedule. Eversource shall have the right to inspect such tests, calibrations, verifications and validations of the data link, metering equipment, data acquisition equipment, transmission equipment, protective equipment and other equipment or software used to implement the provisions of this Local Service Schedule. Upon Eversource's request, the Transmission Customer will provide Eversource a copy of the installation, test and calibration records of the data link, metering equipment, data acquisition equipment, transmission equipment, protective equipment and other equipment or software. Eversource shall, at the Transmission Customer's expense, have the right to monitor the factory acceptance test, the field acceptance test, and the installation of any metering equipment, data acquisition equipment, transmission equipment, protective equipment and other equipment or software used to implement the provisions of this Local Service Schedule.

12.0 Notification

(a) The Transmission Customer shall notify and coordinate with Eversource prior to the commencement of any work or maintenance by the Transmission Customer, Network Member, or contractors or agents performing on behalf of either or both, which may directly or indirectly have an adverse effect on the Transmission Customer or Eversource's data link, or the reliability of the Eversource Transmission System. All notifications for scheduled outages of the data link, metering equipment, data acquisition equipment, transmission equipment, protective equipment and other equipment or software must meet the requirements of the ISO and Eversource.

13.0 Emergency System Operations

(a) The Transmission Customer, at its expense, shall be subject to all applicable emergency operation standards promulgated by NERC, NPCC, ISO and Eversource which may include but not limited to underfrequency relaying equipment, load shedding equipment and voltage reduction equipment.

(b) Eversource reserves the right to take whatever actions they deem necessary to preserve the integrity of the Eversource Transmission System during emergency operating conditions. If the Local Network Service at the points of interconnection is causing harmful physical effects to the Eversource

Transmission System facilities or to its customers (e.g., harmonics, undervoltage, overvoltage, flicker, voltage variations, etc.), Eversource shall promptly notify the Transmission Customer and if the Transmission Customer does not take the appropriate corrective actions immediately, Eversource shall have the right to interrupt Local Network Service under this Local Service Schedule in order to alleviate the situation and to suspend all or any portion of Local Network Service under this Local Service Schedule until appropriate corrective action is taken.

(c) In the event of any adverse condition or disturbance on the Eversource Transmission System or on any other system directly or indirectly interconnected with the Eversource Transmission System, Eversource may, as it deems necessary, take actions or inactions that, in Eversource's sole judgment, result in the automatic or manual interruption of Local Network Service in order to: (i) limit the extent or damage of the adverse condition or disturbance; (ii) prevent damage to generating or transmission facilities; (iii) expedite restoration of service; or (iv) preserve public safety.

14.0 Cost Responsibility

(a) The Transmission Customer shall be responsible for the costs incurred by the Transmission Customer and Eversource to implement the provisions of this Local Service Schedule including, but not limited to, engineering, administrative and general expenses, material and labor expenses associated with the specifications, design, review, approval, purchase, installation, maintenance, modification, repair, operation, replacement, checkouts, testing, upgrading, calibration, removal, and relocation of equipment, or software.

(b) Additionally, the Transmission Customer shall be responsible for all costs incurred by the Transmission Customer and Eversource for on-going operation and maintenance of the metering, telecommunications and safety protection facilities and equipment required to implement the provisions of this Local Service Schedule. Such work shall include, but not limited to, normal and extraordinary engineering, administrative and general expenses, material, and labor expenses associated with the specifications, design, review, approval, purchase, installation, maintenance, modification, repair, operation, replacement, checkouts, testing, upgrading, calibration, removal, or relocation of equipment required to accommodate service under this Local Service Schedule.

15.0 Default

The Transmission Customer's failure to implement the terms and conditions of this Network Operating Agreement will be deemed to be a default under this Local Service Schedule and will result in Eversource seeking, consistent with FERC rules and regulations, immediate termination of service under this Local Service Schedule.

16.0 Regulatory Filings

Nothing contained in this Local Service Schedule or any associated Service Agreement, including this Network Operating Agreement, shall be construed as affecting in any way the right of Eversource to unilaterally make application to the Commission for a change in any portion of this Network Operating Agreement under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

IN WITNESS WHEREOF, the Parties have caused this Network Operating Agreement to be executed by their respective authorized officials as of the date written.

Date: __________________________

Eversource Energy Service Company
by: _______________________________
its Vice President

Transmission Customer
by: _______________________________
its _______________________________

ATTACHMENT ES-H

ANNUAL TRANSMISSION REVENUE REQUIREMENTS

Attachment ES-H Methodology:

This formula sets forth the method that Eversource will use to determine its annual Total Transmission Revenue Requirements. The Transmission Revenue Requirements reflect Eversource's total cost to own, operate and maintain the transmission facilities used for providing Open Access Transmission Service to transmission customers under this Local Service Schedule. The Transmission Revenue Requirements will be an annual formula rate calculation, effective for an initial term commencing on the effective date established by FERC and ending on May 31 of the following year. The calculation will be based on the previous calendar year's FERC Form 1 data, with an estimate of Eversource's current year average plant additions, Construction Work in Progress (CWIP), and the Allowance for Funds Used During Construction (AFUDC) regulatory liability account. Plant additions will be multiplied by a fixed charge carrying cost, and CWIP and the AFUDC regulatory liability account will be multiplied by the Cost of Capital. The revenue requirements will be updated thereafter each June 1 based on actual costs from the Service Year. The true-up information will be based on actual data, in lieu of allocated data if specifically identified in the FERC Form 1. For a capital addition whose cost exceeds $20 million, Eversource will make rate base adjustments to estimates and in the true-up process to represent the estimated and actual in-service dates for the capital addition. Specifically, Eversource will adjust for transmission plant, CWIP, AFUDC regulatory liability, accumulated depreciation and accumulated deferred taxes.

I. Definitions

Capitalized terms not otherwise defined in the Tariff and as used in this formula have the following definitions:

A. Allocation Factors

1. Transmission Wages and Salaries Allocation Factor shall equal the ratio of Eversource's Transmission-related direct wages and salaries, including those of affiliated companies, to Eversource's total direct wages and salaries, including those of affiliated companies, excluding administrative and general wages and salaries.

2. Plant Allocation Factor shall equal the ratio of the sum of total investment in Transmission Plant and Transmission Related General Plant to Total Plant in Service.

B. Terms

Administrative and General Expense shall equal Eversource's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928 and 930.1 and excluding Merger-Related Costs included in FERC Account Nos. 920-935 (other than those in FERC Account Nos. 924, 928 and 930.1, which have already been excluded).

AFUDC Regulatory Liability shall equal the unamortized balance of the capitalized AFUDC booked on Eversource's transmission projects as recorded in FERC Account 254 consistent with Commission orders.

Amortization of Loss on Reacquired Debt shall equal Eversource's expenses as recorded in FERC Account No. 428.1.

Amortization of Investment Tax Credits shall equal Eversource's credits as recorded in FERC Account No. 411.4.

Depreciation Expense for Transmission Plant shall equal Eversource's transmission expense as recorded in FERC Account No. 403.

Dispatch Center means CL&P's CONVEX dispatch center.

Dispatch Center Plant shall equal CL&P's gross plant balance for the Dispatch Center as recorded in FERC Account Nos. 350-359 and 389-399.

Dispatch Center Depreciation Expense shall equal the Dispatch Center depreciation expense as recorded in FERC Account No. 403.

Dispatch Center Amortization of Investment Tax Credits shall equal the Dispatch Center amortization of investment tax credits as recorded in FERC Account No. 411.4.

Dispatch Center Accumulated Deferred Income Taxes shall equal the net of Eversource's Dispatch Center deferred tax balance as recorded in FERC Account Nos. 281-283 and Eversource's Dispatch Center deferred tax balance as recorded in FERC Account No. 190.

Dispatch Center Municipal Tax Expense shall equal the Dispatch Center municipal tax expense as recorded in FERC Account Nos. 408.1 and 409.1.

General Plant shall equal Eversource's gross plant balance as recorded in FERC Account Nos. 389-399, less the Dispatch Center general plant.

General Plant Depreciation Expense shall equal Eversource's general plant expenses as recorded in FERC Account No. 403.

General Plant Depreciation Reserve shall equal Eversource's general plant reserve balance as recorded in FERC Account No. 108 less the portion of such reserve for the Dispatch Center.

Merger-Related Costs shall equal Eversource's amortized merger-related costs as authorized by FERC or by state regulatory order.

Other Regulatory Assets/Liabilities – FAS 106 shall equal the net of Eversource's FAS 106 balance as recorded in FERC Account No. 182.3 and any FAS 106 balance as recorded in Eversource's FERC Account No. 254.

Other Regulatory Assets/Liabilities – FAS 109 shall equal the net of Eversource's FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in Eversource's FERC Account No. 254.

Other Regulatory Assets/Liabilities – merger-related costs shall equal Eversource's unamortized balance of merger-related transmission costs recorded in FERC Account No. 182.3 as authorized by FERC.

Payroll Taxes shall equal those payroll expenses as recorded in Eversource's FERC Account Nos. 408.1 and 409.1.

Plant Held for Future Use shall equal Eversource's balance in FERC Account No. 105.

Prepayments shall equal Eversource's prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal Eversource's expenses as recorded in FERC Account No. 924.

Total Accumulated Deferred Income Taxes shall equal the net of Eversource's deferred tax balance as recorded in FERC Account Nos. 281-283 and Eversource's deferred tax balance as recorded in FERC Account No. 190.

Total Loss on Reacquired Debt shall equal Eversource's expenses as recorded in FERC Account 189.

Total Municipal Tax Expense shall equal Eversource's expenses as recorded in FERC Account Nos. 408.1, 409.1.

Total Plant in Service shall equal Eversource's total gross plant balance as recorded in FERC Account Nos. 301-399.

Total Transmission Depreciation Reserve shall equal Eversource's Transmission reserve balance as recorded in FERC Account 108 less the portion of such reserve for the Dispatch Center.

Transmission Merger-Related Costs shall equal Eversource's amortized merger-related transmission costs as authorized by FERC.

Transmission Operation and Maintenance Expense shall equal Eversource's expenses as recorded in FERC Account Nos. 560, 561.5 – 561.8, 562-564 and 566-576.5 and shall exclude all HQ HVDC expenses booked to accounts 560 through 576.5 and expenses already included in Transmission Support Expense, as described in Section I below, that are included in FERC Account Nos. 560-576.5.

Transmission Plant shall equal Eversource's gross plant balance as recorded in FERC Account Nos. 350-359, less Dispatch Center transmission plant.

Transmission Plant Materials and Supplies shall equal Eversource's balance as assigned to transmission, as recorded in FERC Account 154.

Transmission Related Construction Work in Progress shall equal Eversource's investment in Transmission-related projects as recorded in FERC Account 107 consistent with commission orders.

II. Calculation of Transmission Revenue Requirements

The Transmission Revenue Requirement shall equal the sum of Eversource's (A) Return and Associated Income Taxes, (B) Transmission Depreciation Expense, (C) Transmission Related Amortization of Loss on Reacquired Debt, (D) Transmission Related Amortization of Investment Tax Credits, (E) Transmission Related Municipal Tax Expense, (F) Transmission Related Payroll Tax Expense, (G) Transmission Operation and Maintenance Expense, (H) Transmission Related Administrative and General Expense (I) Transmission Support Expense, and(J) Transmission Related Taxes and Fees Charge.

A. Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate.

1. Transmission Investment Base

The Transmission Investment Base will be the average balances of (a) Transmission Plant, plus (b) Transmission Related General Plant, plus (c) Transmission Plant Held for Future Use, plus (d) Transmission Related Construction Work in Progress, less (e) Transmission Related Depreciation Reserve, less (f) Transmission Related Accumulated Deferred Taxes, plus (g) Transmission Related Loss on Reacquired Debt, plus (h) Other Regulatory Assets/Liabilities, less (i) AFUDC Regulatory Liability, plus (j) Transmission Prepayments, plus (k) Transmission Materials and Supplies, plus (l) Transmission Related Cash Working Capital.

(a) Transmission Plant will equal the balance of Eversource's investment in Transmission Plant.

(b) Transmission Related General Plant shall equal Eversource's balance of investment in General Plant multiplied by the Transmission Wages and Salaries Allocation Factor.

(c) Transmission Plant Held for Future Use shall equal the balance of Transmission Plant Held for Future Use.

(d) Transmission Related Construction Work in Progress shall equal the portion of Eversource's investment in Transmission-related projects as recorded in FERC Account 107 consistent with Commission orders.

(e) Transmission Related Depreciation Reserve shall equal the balance of Total Transmission Depreciation Reserve, plus the balance of Transmission Related General Plant Depreciation Reserve. Transmission Related General Plant Depreciation Reserve shall equal the product of General Plant Depreciation Reserve and the Transmission Wages and Salaries Allocation Factor.

(f) Transmission Accumulated Deferred Taxes shall equal Eversource's electric balance of Total Accumulated Deferred Income Taxes multiplied by the Plant Allocation Factor, less the transmission and general plant components of Dispatch Center Accumulated Deferred Income Taxes.

(g) Transmission Related Loss on Reacquired Debt shall equal Eversource's electric balance of Total Loss on Reacquired Debt multiplied by the Plant Allocation Factor.

(h) Other Regulatory Assets/Liabilities shall equal Eversource's electric balance of any deferred rate recovery of FAS 106 expense multiplied by the Transmission Wages and Salaries Allocation Factor, plus Eversource's electric balance of FAS 109 multiplied by the Plant Allocation Factor, plus Eversource's unamortized balance of merger-related transmission costs recorded in FERC Account No. 182.3 as authorized by FERC.

(i) AFUDC Regulatory Liability shall equal the unamortized balance of the capitalized AFUDC booked on Eversource's transmission projects as recorded in FERC Account 254 consistent with Commission orders.

(j) Transmission Prepayments shall equal Eversource's electric balance of Prepayments multiplied by the Transmission Wages and Salaries Allocation Factor.

(k) Transmission Materials and Supplies shall equal Eversource's electric balance of Transmission Plant Materials and Supplies.

(l) Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Transmission Operation and Maintenance Expense and Transmission Related Administrative and General Expense.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) Eversource's Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon the capital structure at the end of each year and will equal the sum of:

(i) the long term debt component, which equals the product of the actual weighted average embedded cost to maturity of Eversource's long-term debt then outstanding and the ratio that long-term debt is to Eversource's total capital.

(ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of Eversource's preferred stock then outstanding and the ratio that preferred stock is to Eversource's total capital.

(iii) the return on equity component, shall equal the product of Eversource's return on equity ("ROE") of 10.57% and the ratio that common equity is to Eversource's total capital.

(b) Federal Income Tax shall equal

[(A+[(C+B)/D]x (FT)] divided by (1-FT)

where FT is the Federal Income Tax Rate and A is the sum of the preferred stock component and the return on equity component, as determined in Sections II.A.2.(a)(ii) and (iii) above, B is Transmission Related Amortization of Investment Tax Credits, as determined in Section II.D., below, C is the Equity AFUDC component of Transmission Depreciation Expense, as defined in Section II.B., and D is Transmission Investment Base, as Determined in II.A.1., above.

(c) State Income Tax shall equal

[A+[(C+B)/D] + Federal Income Tax)x(ST)] divided by (1-ST)

where ST is the State Income Tax Rate, A is the sum of the preferred stock component and return on equity component determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section II.D. below, C is the equity AFUDC component of Transmission Depreciation Expense, as defined in Section II.B., D is the Transmission Investment Base, as determined in II.A.1., above and Federal Income Tax is the rate determined in Section II.A.2.(b) above.

B. Transmission Depreciation Expense shall equal the sum of Depreciation Expense for Transmission Plant, plus an allocation of General Plant Deprecation Expense calculated by multiplying General Plant Depreciation Expense by the Transmission Wages and Salaries Allocation Factor, less the amortization of AFUDC Regulatory Credit as recorded in Account 407.4, less the transmission plant and general plant components of Dispatch Center Depreciation Expense.

C. Transmission Related Amortization of Loss on Reacquired Debt shall equal Eversource's electric Amortization of Loss on Reacquired Debt multiplied by the Plant Allocation Factor.

D. Transmission Related Amortization of Investment Tax Credits shall equal Eversource's electric Amortization of Investment Tax Credits multiplied by the Plant Allocation Factor less the transmission plant and general plant components of Dispatch Center Amortization of Investment Tax Credits.

E. Transmission Related Municipal Tax Expense shall equal Eversource's electric Total Municipal Tax Expense multiplied by the Plant Allocation Factor, less the transmission plant and general plant components of Dispatch Center Municipal Tax Expense.

F. Transmission Related Payroll Tax Expense shall equal Eversource's electric Payroll Tax expense, multiplied by the Transmission Wages and Salaries Allocation Factor.

G. Transmission Operation and Maintenance Expense shall equal Transmission Operation and Maintenance Expenses.

H. Transmission Related Administrative and General Expenses shall equal the sum of (1) Eversource's Administrative and General Expenses multiplied by the Transmission Wages and Salaries

Allocation Factor, (2) Property Insurance multiplied by the Transmission Plant Allocation Factor, (3) Expenses included in Account 928 (excluding Merger-Related Costs included in Account 928) related to FERC Assessments multiplied by the Plant Allocation Factor, plus any other Federal and State transmission related expenses or assessments in Account 928 plus specific transmission related expenses included in Account 930.1, plus Transmission Merger-Related Costs and, (4) specific transmission related public education expenses included in Account 426.54.

I. Transmission Support Expense shall equal the expense paid by Eversource for transmission support.

J. Transmission Related Taxes and Fees Charge shall include any fee or assessment imposed by any governmental authority on service provided under this Local Service Schedule that is not specifically identified under any other section of this Local Service Schedule.

ATTACHMENT ES-I

ANNUAL LOCALIZED TRANSMISSION REVENUE REQUIREMENT

Attachment ES-I Methodology

This formula sets forth the method that Eversource will use to determine its annual total revenue requirements for each Localized Facility ("Localized Transmission Revenue Requirement"). Subsequent references in this formula to "Localized Facility" and "Localized Transmission Revenue Requirement" refer to the Localized Facility and Localized Facility Revenue Requirement for each individual Localized Transmission Project. Each Localized Facility is identified in Section 16.3.

The Localized Transmission Revenue Requirement will be calculated for an initial term for a Localized Facility commencing on the date of the New England System Operator's Schedule 12C cost allocation determination for the Localized Facility and ending on the May 31st following the date approved by the Commission for including the costs of the Localized Facilities in this Attachment ES-I ("Initial Term"), and continuing thereafter for successive 12 month periods commencing each June 1st ("Rate Year"). The Localized Transmission Revenue Requirement for the Initial Term for a Localized Facility will be calculated based on the estimated cost of the Localized Facilities for such period, and will be charged to customers in equal monthly installments beginning on the date permitted by the Commission, and continuing through the end of the Initial Term. The Localized Transmission Revenue Requirement for the Initial Term for a Localized Facility will be trued up for the appropriate calendar year by June 30th of the succeeding year(s) based on actual costs for the Initial Term.

The Localized Transmission Revenue Requirement for a Localized Transmission Project for a Rate Year commencing after the Initial Term (and for succeeding Rate Years) will be an annual calculation based on the previous calendar year's Localized Transmission Revenue Requirements, plus the forecasted revenue requirements of Localized Facilities to be placed in service in the upcoming Rate Year. Each June 30th,

the Localized Transmission Revenue Requirement in effect during the portion of the Rate Year that occurred in the previous calendar year will be trued-up based on actual costs from such previous calendar year.

The true-up information will be based on actual data, in lieu of allocated data if specifically identified in the FERC Form 1, or based on allocated data if such specific information is not identified. For a capital addition whose cost exceeds $20 million, Eversource will make rate base adjustments to estimates and in the true-up process to represent the estimated and actual in-service dates for the capital addition. Specifically, Eversource will adjust for transmission plant, accumulated depreciation and accumulated deferred taxes.

The Localized Transmission Revenue Requirement for Eversource that is based on data for calendar year 2004 or later shall include a Localized Incremental Return and Associated Income Taxes on Eversource's Localized PTF transmission plant investments placed in-service on or after January 1, 2004 (such investments referred to herein as "Localized Post-2003 PTF Investment"). The Localized Incremental Return and Associated Income Taxes for Localized Post-2003 Investment shall incorporate an incentive ROE adder of 100 basis points for plant investments placed in service by December 31, 2008 or as otherwise permitted in Docket Nos. ER04-157 et al. for any projects included in the Regional System Plan ("RSP"), and shall incorporate any incentive ROE adder approved by the FERC under Order No. 679 for other plant investments. The total ROE for any project, including any authorized ROE incentives for Post-2003 PTF Investment and any other incentive ROE approved by FERC under Order No. 679 shall be capped by the top of the applicable zone of reasonableness determined by FERC for the relevant period. The data used in determining Eversource's Localized Incremental Return and Associated Taxes for Localized Post-2003 Investment shall be based on actual data in lieu of allocated data if specifically identified in Eversource accounting records.

I. Definitions

Capitalized terms not otherwise defined in the Tariff and as used in this formula have the following definitions:

A. Allocation Factors

1. Localized Transmission Allocation Factor shall equal the ratio of Localized Transmission Plant in Service to total investment in Transmission Plant.

2. Total Localized Plant Allocation Factor shall equal the ratio of Localized Transmission Plant in Service to Total Plant in Service.

3. Transmission Wages and Salaries Allocation Factor shall equal the ratio of Eversource's Transmission-related direct wages and salaries, including those of affiliated companies, to Eversource's total direct wages and salaries, including those of affiliated companies, and excluding administrative and general wages and salaries.

B. Terms

Administrative and General Expense shall equal Eversource's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928 and 930.1 and excluding Merger-Related Costs included in FERC Account Nos. 920-935 (other than those in FERC Account Nos. 924, 928 and 930.1, which have already been excluded).

Amortization of Loss on Reacquired Debt shall equal Eversource's expenses as recorded in FERC Account No. 428.1.

Amortization of Investment Tax Credits shall equal Eversource's expenses as recorded in FERC Account No. 411.4.

Depreciation Expense for Localized Transmission Plant shall equal Eversource's Localized Facilities expenses as recorded in FERC Account No. 403.

Dispatch Center means CL&P's CONVEX dispatch center.

Dispatch Center Plant shall equal CL&P's gross plant balance for the Dispatch Center as recorded in FERC Account Nos. 350-359 and 389-399.

General Plant shall equal Eversource's gross plant balance as recorded in FERC Account Nos. 389-399 less Dispatch Center general plant.

General Plant Depreciation Expense shall equal Eversource's general plant expenses as recorded in FERC Account No. 403 less the portion of such expense for the Dispatch Center.

General Plant Depreciation Reserve shall equal Eversource's general plant reserve balance as recorded in FERC Account No. 108 less the portion of such reserve for the Dispatch Center.

Merger-Related Costs shall equal Eversource's amortized merger-related costs as authorized by FERC or by state regulatory order.

Other Regulatory Assets/Liabilities shall equal Eversource's unamortized balance of merger-related transmission costs recorded in FERC Account No. 182.3 as authorized by FERC.

Payroll Taxes shall equal those payroll expenses as recorded in Eversource's FERC Account Nos. 408.1 and 409.1.

Prepayments shall equal Eversource's prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal Eversource's expenses as recorded in FERC Account No. 924.

Total Accumulated Deferred Income Taxes shall equal the net of Eversource's deferred tax balance as recorded in FERC Account Nos. 281-283 and Eversource's deferred tax balance as recorded in FERC Account No. 190.

Total Loss on Reacquired Debt shall equal Eversource's expenses as recorded in FERC Account 189.

Total Municipal Tax Expense shall equal Eversource's expenses as recorded in FERC Account Nos. 408.1, 409.1.

Transmission Merger-Related Costs shall equal Eversource's amortized merger-related transmission costs as authorized by FERC.

Localized Transmission Plant in Service shall equal Eversource's Localized Facilities gross plant balance as recorded in FERC Account Nos. 350-359.

Localized Transmission Plant Held for Future Use shall equal Eversource's Localized Facilities balance as recorded in FERC Account 105.

Localized Transmission Depreciation Reserve shall equal Eversource's Localized Facilities reserve balance as recorded in FERC Account 108.

Transmission Operation and Maintenance Expense shall equal Eversource's expenses as recorded in FERC Account Nos. 560, 561.5 – 561.8, 562-564 and 566-576.5 and shall exclude all HQ HVDC expenses booked to accounts 560 through 576.5 and expenses already included in Transmission Support Expense, as described in Section I below, which are included in FERC Account Nos. 560-576.5.

Transmission Plant shall equal Eversource's gross plant balance as recorded in FERC Account Nos. 350-359.

Transmission Plant Materials and Supplies shall equal Eversource's balance as assigned to transmission, as recorded in FERC Account 154.

Total Plant in Service shall equal Eversource's total gross plant balance as recorded in FERC Account Nos. 301-399.

II. Calculation of Localized Transmission Revenue Requirements

The Localized Transmission Revenue Requirements shall equal the sum of Eversource's (A) Localized Return and Associated Income Taxes (including the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment), (B) Localized Transmission Depreciation Expense, (C) Localized

Transmission Related Amortization of Loss on Reacquired Debt, (D) Localized Transmission Related Amortization of Investment Tax Credits, (E) Localized Transmission Related Municipal Tax Expense, (F) Localized Transmission Related Payroll Tax Expense, (G) Localized Transmission Operation and Maintenance Expense, (H) Localized Transmission Related Administrative and General Expense , (I) Localized Transmission Support Expense, and (J) Localized Transmission Related Taxes and Fees Charge. The Localized Incremental Return and Associated Income Taxes for Localized Post-2003 PTF Investment for Eversource shall be calculated using the investment base components specifically identified in Section A.1 of the formula below.

A. Localized Return and Associated Income Taxes shall equal the product of the Localized Transmission Investment Base and the Cost of Capital Rate. To calculate the Localized Incremental Return and Associated Income Taxes for Localized Post-2003 PTF Investment, Localized Transmission Plant will only include Sections II.A.1.(a), (c), and (d), in the manner indicated.

1. Localized Transmission Investment Base

The Localized Transmission Investment Base will be the average balances of (a) Localized Transmission Plant, plus (b) Localized Transmission Plant Held for Future Use less (c) Localized Transmission Related Depreciation Reserve, less (d) Localized Transmission Related Accumulated Deferred Taxes, plus (e) Localized Transmission Related Loss of Reacquired Debt, plus (f) Other Regulatory Assets/Liabilities, plus (g) Localized Transmission Prepayments, plus (h) Localized Transmission Materials and Supplies, plus (i) Localized Transmission Related Cash Working Capital.

(a) Localized Transmission Plant will equal the balance of (1) Eversource's investment in Localized Transmission Plant plus, (2) Eversource's balance of investment in General Plant multiplied by the Transmission Wages and Salaries Allocation Factor, further multiplied by the Localized Transmission Allocation Factor. In order to calculate the Localized Incremental Return and Associated Income Taxes for Localized Post-2003 PTF Investment, Localized Post-2003 PTF Transmission Plant shall be separately identified.

(b) Localized Transmission Plant Held for Future Use shall equal Eversource's balance of Localized Transmission Plant Held for Future Use.

(c) Localized Transmission Related Depreciation Reserve shall equal the balance of Localized Transmission Depreciation Reserve plus the balance of Localized Transmission Related General Plant Depreciation Reserve. Localized Transmission Related General Plant Depreciation Reserve shall equal the product of General Plant Depreciation Reserve and the Transmission Wages and Salaries Allocation Factor, further multiplied by the Localized Transmission Allocation Factor. In order to calculate the Localized Incremental Return and Associated Income Taxes for Localized Post-2003 PTF Investment, Localized Transmission Related Depreciation Reserve associated with Localized Post-2003 PTF Investment shall equal Eversource's balance of Localized Transmission Depreciation Reserve.

(d) Localized Transmission Related Accumulated Deferred Taxes shall equal Eversource's electric balance of Total Accumulated Deferred Income Taxes, multiplied by the Total Localized Plant Allocation Factor. To calculate the Localized Incremental Return and Associated Income Taxes for Localized Post-2003 PTF Investment, Localized Transmission Related Accumulated Deferred Taxes associated with Localized Post-2003 PTF Investment shall equal Eversource's electric balance of Total Accumulated Deferred Income Taxes multiplied by the Total Localized Plant Allocation Factor.

(e) Localized Related Loss on Reacquired Debt shall equal Eversource's electric balance of Total Loss on Reacquired Debt multiplied by the Total Localized Plant Allocation Factor.

(f) Localized Transmission Other Regulatory Assets/Liabilities shall equal Eversource's unamortized balance of merger-related transmission costs recorded in FERC Account No. 182.3 as authorized by FERC multiplied by the Localized Transmission Allocation Factor.

(g) Localized Transmission Prepayments shall equal Eversource's electric balance of Prepayments multiplied by the Transmission Wages and Salaries Allocation Factor and further multiplied by the Localized Transmission Allocation Factor.

(h) Localized Transmission Materials and Supplies shall equal Eversource's electric balance of Transmission Plant Materials and Supplies multiplied by the Localized Transmission Allocation Factor.

(i) Localized Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of (i) Localized Transmission Operation and Maintenance Expense, plus (ii) Localized Administrative and General Expense.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) Eversource's Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon the average capital structure and will equal the sum of:

(i) the long term debt component, which equals the product of the actual weighted average embedded cost to maturity of Eversource's long-term debt then outstanding and the ratio that long-term debt is to Eversource's total capital.

(ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of Eversource's preferred stock then outstanding and the ratio that preferred stock is to Eversource's total capital.

(iii) the return on equity component shall equal the product of Eversource's return on equity ("ROE") of 11.07% and the ratio that common equity is to Eversource's total capital. In order to calculate the Localized Incremental Return and Associated Taxes for Post-2003 PTF Investment, the Localized Incremental Return on Equity shall be the product of (1) Eversource's incremental return on equity of 1% for transmission plant investments associated with projects included in the RSP and placed in service by December 31, 2008 or otherwise permitted in Docket Nos. ER04-157 et al., and (2) any ROE incentive adder approved by the FERC under Order No. 679 for other transmission plant investments, provided that the total ROE for any project, including any such ROE incentives, shall be capped by the top of the applicable zone of reasonableness determined by FERC for the relevant period; and (3) the ratio of that common equity to total capital.[1]

(b) Federal Income Tax shall equal

[(A+[(C+B)/D]) x (FT)] divided by (1-FT) where FT is the Federal Income Tax Rate and A is the sum of the preferred stock component and the return on equity component, as determined in Sections II.A.2.(a)(ii) and (iii) above, B is Localized Transmission Related Amortization of Investment Tax Credits, as determined in Section II.D., below, C is the Equity AFUDC component of Localized Transmission Depreciation Expense, as defined in Section II.B., and D is Localized Transmission Investment Base, as Determined in II.A.1., above.

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1 FERC Form-730 contains a list of transmission projects for which FERC has granted incentives under Order No. 679.

(c) State Income Tax Shall equal:

[(A+[(C+B)/D] + Federal Income Tax) x (ST)] divided by (1-ST)

where ST is the State Income Tax Rate, A is the sum of the preferred stock component and return on equity component determined in Sections II.A.2.(a)(ii) and (iii) above, B is the

Localized Transmission Related Amortization of Investment Tax Credits as determined in Section II.D. below, C is the equity AFUDC component of Localized Transmission Depreciation Expense, as defined in Section II.B., D is the Localized Transmission Investment Base, as determined in II.A.1. above and Federal Income Tax is the rate determined in Section II.A.2.(b) above.

B. Localized Transmission Depreciation Expense shall equal the sum of Depreciation Expense for Localized Transmission Plant, plus an allocation of General Plant Deprecation Expense calculated by multiplying General Plant Depreciation Expense by the Transmission Wages and Salaries Allocation Factor and further multiplied by the Localized Transmission Allocation Factor.

C. Localized Transmission Related Amortization of Loss on Reacquired Debt shall equal Eversource's electric Amortization of Loss on Reacquired Debt multiplied by the Total Localized Plant Allocation Factor.

D. Localized Transmission Related Amortization of Investment Tax Credits shall equal Eversource's electric Amortization of Investment Tax Credits multiplied by the Total Localized Plant Allocation Factor.

E. Localized Transmission Related Municipal Tax Expense shall equal Eversource's Total Municipal Tax Expense multiplied by the Total Localized Plant Allocation Factor.

F. Localized Transmission Related Payroll Tax Expense shall equal Eversource's electric Payroll Taxes expense, multiplied by the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Localized Transmission Allocation Factor.

G. <u>Localized Transmission Operation and Maintenance Expense</u> shall equal Eversource's Transmission Operation and Maintenance Expense multiplied by the Localized Transmission Allocation Factor.

H. <u>Localized Transmission Related Administrative and General Expense</u> shall equal the sum of (1) Eversource's Administrative and General Expense multiplied by the Transmission Wages and Salaries Allocation Factor and further multiplied by the Localized Transmission Allocation Factor, (2) Property Insurance multiplied by the Total Localized Plant Allocation Factor, (3) Expenses included in Account 928 <u>(excluding Merger-Related Costs included in Account 928)</u> related to FERC Assessments multiplied by the Total Localized Plant Allocation Factor, (4) Federal and State transmission related expenses or assessments in Account 928 multiplied by the Localized Transmission Allocation Factor, (5) specific transmission related expenses included in Account No. 930.1, multiplied by the Localized Transmission Allocation Factor, plus Transmission Merger-Related Costs multiplied by the Localized Transmission Allocation Factor and (6) specific Localized Facility related public education expenses included in Account 426.54.

I. <u>Transmission Support Expense</u> shall equal the expense paid by Eversource for transmission support for Localized Facilities.

J. <u>Transmission Related Taxes and Fees Charge</u> shall include any fee or assessment imposed by any governmental authority on transmission service provided under this Local Service Schedule that is not specifically identified under any other section of this Local Service Schedule, multiplied by the Localized Transmission Allocation Factor.

SCHEDULE 21-ES

ATTACHMENT ES-L

Creditworthiness Procedures

1. **General Information**

All customers taking any service under Schedule 21-ES, the Local Service Schedule ("LSS"), and the associated schedules of The Connecticut Light and Power Company, Western Massachusetts Electric Company, and Public Service Company of New Hampshire ("Eversource") must meet the terms of this Attachment ES-L.

2. **Establishing Creditworthiness**

a) Each customer's creditworthiness must be established before receiving transmission services from Eversource. A customer will be evaluated at the time that its application for transmission service is provided to Eversource based on the creditworthiness information required under this Attachment ES-L. Eversource shall conduct a credit review of each Transmission Customer not less than annually or upon reasonable request by the Transmission Customer.

b) Eversource will review the customer's creditworthiness information for completeness and will notify the customer if additional information is required.

c) Upon completion of a creditworthiness evaluation of a customer, Eversource will forward a written evaluation to the customer if they determine that Financial Assurance must be provided.

3. Financial Information

Customers requesting transmission service must submit if available the following:

a) All current rating agency reports of the customer from Standard and Poor's ("S&P"), Moody's Investors Service ("Moody's"), and/or Fitch Ratings ("Fitch").

b) A Management Discussion and Analysis ("MD&A") along with audited financial statements provided by an independent registered public accounting firm or a registered

independent auditor for the three (3) most recent fiscal years, or the period of the customer's existence, if shorter than three (3) years.

4. Creditworthiness – Qualification for Unsecured Credit

a) A customer may receive unsecured credit from Eversource equivalent to three (3) months of the transmission charges. The customer must meet at least one of the following criteria:

(i) If rated, the customer's lowest rating from the three rating agencies on its senior unsecured long-term debt; or if the customer does not have such a rating, then one rating level below the rating then assigned to the customer's corporate credit rating, as follows:

1. a Standard and Poor's or Fitch rating of at least BBB, or

2. a Moody's rating of least Baa2.

(ii) If un-rated or if rated below BBB/Baa2, as described in 4(a)(i) above, the customer must meet all of the following creditworthiness criteria for the three (3) most recent fiscal years:

1. A Capitalization Ratio (Debt divided by the sum of shareholders' equity and Debt) of no more than 60 percent Debt, where "Debt" is defined as the sum of all long-term and short-term debt, preferred securities and capital leases. Each of which is recorded in accordance with generally accepted accounting principles;

2. Earnings before interest, taxes, depreciation and amortization ("EBITDA") in the most recent fiscal quarter divided by interest expense (ratio of EBITDA-to-interest expense of at least three (3) times); and

3. Audited Financial Statements with an unqualified auditor opinion.

b) If the customer relies on the creditworthiness of a parent company, the parent company must satisfy the ratings criteria in Section 4(a) above, and must provide to Eversource a written

guarantee that it will be unconditionally responsible for all financial obligations associated with the customer's receipt of transmission service from Eversource.

c) If the customer or the customer's parent company do not qualify for unsecured credit under Sections 4(a) or (b) above, the customer can still qualify for unsecured credit equivalent to three (3) months of transmission service charges, if:

(i) the customer has, on a rolling basis, 12 consecutive months of payments to Eversource with no missed, late or defaults in payment; or

(ii) the customer has an executed long-term contract for the sale of the full output (energy and capacity) of its generating unit and either has executed a corresponding service transmission service agreement under Schedule 21-ES for the transmission of that output or the execution of such agreement is pending the customer's demonstration of creditworthiness.

5. Financial Assurance

If the customer does not meet the applicable requirements for unsecured credit set out in Section 4 then the customer must either:

a) pay in advance an amount equal to the lesser of the total charge for transmission service not less than five (5) days in advance of the commencement of service, in which case Eversource will pay to the customer interest on the amounts not yet due to Eversource, computed in accordance with 18 C.F.R. §35.19(a)(2)(iii) of the Commission's Regulations; or

b) obtain Financial Assurance in the form of a letter of credit or a parent guarantee equal to the equivalent of three (3) months of transmission service charges prior to receiving service.

(i) The letter of credit must be one or more irrevocable, transferable standby letters of credit issued by a United States commercial bank or a United States branch of a foreign bank provided that such customer is not an affiliate of such bank. The issuing bank must have a credit rating of at least A2 from Moody's or an A rating from S&P or Fitch, or an equivalent credit rating by another nationally recognized rating service reasonably acceptable to Eversource, provided that such bank shall have assets totaling not less than

ten billion dollars ($10,000,000,000). All costs of the letter of credit shall be borne by the applicant for such letter of credit. In the event of an inconsistency in the ratings by Moody's, S&P, or Fitch, a "split rating", the lowest credit rating shall apply.

(ii) If the credit rating of a bank or other financial institution issuing a letter of credit to a customer falls below the levels specified in Section 5(b)(i) above, the customer shall have three (3) business days to obtain a suitable letter of credit from another bank or other financial institution that meets the specified levels unless Eversource agrees in writing to extend such period.

6. Notifications

Each customer must inform Eversource in writing within three (3) business days of any material change in its or its letter of credit issuer's financial condition, and if the customer qualifies under Section 4(b), that of its parent company. A material change in financial condition may include, without limitation, the following:

a) change in ownership by way of a merger, acquisition, or substantial sale of assets;
b) downgrade by a recognized major financial rating agency;
c) placement on credit watch with negative implications by a major financial rating agency;
d) a bankruptcy filing by the customer or parent;
e) any action requiring the filing of a SEC Form 8-K;
f) declaration of or acknowledgement of insolvency;
g) report of a significant quarterly loss or decline in earnings;
h) resignation of key officer(s); or
i) issuance of a regulatory order and/or the filing of a lawsuit that could materially adversely impact current or future financial results.

7. Ongoing Financial Review

Each customer is required to submit to Eversource annually or when issued, as applicable:

a) current rating agency reports;
b) audited financial statements from an independent registered public accounting firm or a registered independent auditor; and
c) SEC Forms 10-K and 8-K, promptly upon their filing.

8. Change in Creditworthiness Status

A customer who has been extended unsecured credit pursuant to Section 4, must comply with the terms of Financial Assurance in Section 5, if one or more of the following conditions apply:

a) the customer no longer meets the applicable criteria for unsecured credit in Section 4;

b) the customer exceeds the amount of unsecured credit extended by Eversource, in which case Financial Assurance equal to the amount of exceeded unsecured credit must be provided within five (5) business days; or

c) the customer has missed two or more payments for any of the transmission services provided by Eversource in the last twelve (12) months.

9. Procedures for Changes in Credit Levels and Collateral Requirements

a) Eversource shall issue notice to a customer of any changes to the approved credit levels and/or collateral requirements within five (5) business days after (1) receiving notification of any material changes in financial condition under Section 6 above; (2) receiving the information required for the customer's ongoing financial review listed in Section 7 above; or (3) the occurrence of any of the events leading to a change in creditworthiness requirements listed in Section 8 above.

b) A customer may submit a written request that Eversource provide an explanation of the reasons for the changes in credit levels and/or collateral requirements within five (5) business days after receiving notification of the changes. Eversource will provide a written response within five (5) business days after receiving such a request.

10. Contesting Creditworthiness Determinations

A customer may contest Eversource's determination of its creditworthiness by submitting a written request for re-evaluation within 20 calendar days of being notified of the creditworthiness determination. The request should provide information supporting the basis for a re-evaluation of the customer's creditworthiness. Eversource will review the request and respond within 20 calendar days of receipt.

11. Process for Changing Credit Requirements

a) In the event Eversource plans to revise the Schedule 21-ES requirements for credit levels or collateral requirements described in this Attachment ES-L, they will make a filing under Section 205 of the Federal Power Act.

b) Eversource shall provide written notification to ISO-NE and stakeholders of any filing described above, at least 30 days in advance of such filing.

c) Filing notifications shall include a detailed description of the filing, including a redlined document containing revised changes(s) to this Attachment ES-L.

d) Eversource shall consult with interested stakeholders upon request.

e) Following Commission acceptance of such filing and upon the effective date, Eversource shall revise its Attachment ES-L an updated version of Schedule 21-ES shall be posed to the ISO-NE web site.

f) When Eversource changes its credit requirements for service under Schedule 21-ES, the customer is responsible for forwarding updated financial information to Eversource. The customer must indicate whether the change affects its ability to meet the requirements of Attachment ES-L. In cases where the customer's credit status has changed, the customer must take the necessary steps to comply with the revised credit requirements of Attachment ES-L by the effective date of the change.

12. Suspension of Service

Eversource may immediately suspend service (with notification to the Commission) to a customer, and may initiate proceedings with the Commission to terminate service, if the customer does not meet the terms described in Sections 4 through 8 at any time during the term of service or if the customer's payment obligations to Eversource exceed the amount of unsecured or secured credit to which it is entitled under this Attachment ES-L. A customer is not obligated to pay for transmission service that is not provided as a result of a suspension of service.

ATTACHMENT F

ANNUAL TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirements for each PTO will reflect the PTO's costs with respect to Pool Supported PTF and the HTF, including costs attributable to those PTOs deemed to own or support PTF pursuant to Section II.49 of the Tariff. The Transmission Revenue Requirements will be an annual calculation based on the previous year's calendar data as shown, in the case of PTOs that are subject to the Commission's jurisdiction, in the PTO's FERC Form 1 report for that year; provided, however, that if a PTO is deemed to own or support PTF pursuant to Section II.49 of the Tariff, such PTO may include the costs as incurred by its Related Person for PTF facilities and Transmission Support Expenses as the basis for establishing its initial and subsequent Annual Transmission Revenue Requirements, only until such PTO has a full calendar year of cost data under its ownership. Such PTO's costs will be determined from FERC Form 1 data if available, or if not available, from other supporting data certified by an auditor of the PTO or Related Person, and in a format comparable to that used to report such costs in FERC Form 1. Such costs shall be based on actual data in lieu of allocated data if specifically identified in the Form 1 report in accordance with the following formula and Schedule 12:

I. The Transmission Revenue Requirement shall equal the sum of the PTO's (A) Return and Associated Income Taxes, (B) Transmission Depreciation and Amortization Expense, (C) Transmission Related Amortization of Loss on Reacquired Debt, (D) Transmission Related Amortization of Investment Tax Credits, (E) Transmission Related Municipal Tax Expense, (F) Transmission Related Payroll Tax Expense, (G) Transmission Operation and Maintenance Expense, (H) Transmission Related Administrative and General Expense, (I) Transmission Related Integrated Facilities Charges, minus (J) Transmission Support Revenue, plus (K) Transmission Support Expense, plus (L) Transmission Related Expense from Generators, plus (M) Transmission Related Taxes and Fees Charge, minus (N) Revenue for Short-Term service under the OATT and (O) Transmission Rents Received from Electric Property.

The details for implementation of Attachment F, as well as the definitions of the terms used in the Attachment F formula, shall be established in accordance with the Attachment F Implementation Rule contained in this OATT.

ATTACHMENT F
IMPLEMENTATION RULE

This rule sets forth details with respect to the determination each year of the Transmission Revenue Requirements for each PTO. Such Transmission Revenue Requirements shall reflect the PTO's costs for Pool Transmission Facilities ("PTF") and the Highgate Transmission Facilities ("HTF"), including costs attributable to those PTOs deemed to own or support PTF pursuant to Section II.49 of the Tariff. The Transmission Revenue Requirements for each PTO will reflect the PTO's costs with respect to Pool Supported PTF and the HTF. The Transmission Revenue Requirements will be an annual calculation based on the previous year's calendar data as shown, in the case of PTOs which are subject to the Commission's jurisdiction, in the PTO's FERC Form 1 report for that year; provided, however, that if a PTO is deemed to own or support PTF, such PTO may include the costs as incurred by its Related Person for PTF facilities and Transmission Support Expenses as the basis for establishing its initial and subsequent Annual Transmission Revenue Requirements, only until such PTO has a full calendar year of cost data under its ownership. Such PTO's costs will be determined from FERC Form 1 data if available, or if not available, from other supporting data certified by an auditor of the PTO or Related Person, and in a format comparable to that used to report such costs in FERC Form 1. Such costs shall be based on actual data in lieu of allocated data if specifically identified in the Form 1 report in accordance with the following formula and Schedule 12. The HTF Transmission Revenue Requirements shall be subject to the limitations of inclusion of such costs as set forth in Appendix B to this Attachment. The owners of the HTF, or their designated agent, will submit the annual HTF Transmission Revenue Requirements calculation based on the previous calendar year's cost data from their FERC Form 1 or equivalent information from their official books and records, as appropriate.

The Post-96 Transmission Revenue Requirement for each PTO that is based on data for calendar year 2004 or later shall include an Incremental Return and Associated Income Taxes on the PTO's PTF transmission plant investments included in the Regional System Plan and placed in-service on or after January 1,2004 (such investments referred to herein as "Post-2003 PTF Investment"). The Incremental Return and Associated Income Taxes for Post-2003 PTF Investment shall incorporate an incentive ROE adder of 100 basis points for plant investment placed in service by December 31, 2008 or as otherwise permitted in Docket Nos. ER04-157, et al. for any projects included in the RSP, and shall incorporate any incentive ROE adder approved by the FERC under Order No. 679 for other plant investments and for MPRP CWIP and NEEWS CWIP. The total ROE for any project, including any authorized ROE incentives for Post-2003 PTF Investment and any other incentive ROE approved by FERC under Order

No. 679 shall be capped by the top of the applicable zone of reasonableness determined by FERC for the relevant period. The data used in determining each PTO's Incremental Return and Associated Taxes for Post-2003 Investment shall be based on actual data in lieu of allocated data if specifically identified in the PTO's accounting records.

The Post-1996 Pool PTF Rate, as calculated pursuant to Schedule 9, shall include for each PTO a Forecasted Transmission Revenue Requirement calculated in accordance with Appendix C to this Attachment F Implementation Rule. Additionally, the Pre-1997 and Post-1996 Pool PTF Rates shall include an Annual True-up calculated in accordance with Appendix C to this Attachment F Implementation Rule.

The PTOs shall make an annual informational filing on or before July 31 of each year showing the Pool PTF Rate in effect for the period beginning June 1 of that year through May 31 of the subsequent year.Further, the informational filing with respect to the determination of the Pool PTF Rate will include a breakdown by PTO of the amount of the change in PTF and HTF investment during the prior year and the PTF and HTF retirements or additions causing such change to beginning and end-of-year PTF balances and HTF balances (although beginning-of-year PTF balances and HTF balances are not used in the formula itself), and any additions to PTF and HTF, retirements of PTF and HTF, and reclassifications of PTF and HTF during the year for each PTO. If there are any corrections made to the information reflected in the informational filing after it has been submitted, the PTOs will file corrections to the informational filing. At least forty-five days before the informational filing is made with the Commission, the PTOs shall make available to Transmission Customers and any other interested parties a draft of the proposed filing for review and comment prior to the filing by posting such draft on the ISO website. The filing of the information filing does not re-open the formula rate set forth below for review, but rather is contestable only with respect to the accuracy of the information contained in the informational filing.

The ISO shall have the discretion to conduct audits of such charges, with advisory Stakeholder input on the scope of audit, including on any agreed-upon procedures to be used by the auditor. In this provision, the term “agreed-upon procedures” shall have the meaning afforded to it by the American Institute of Certified Public Accountants.

I. DEFINITIONS

Capitalized terms not otherwise defined in the Tariff and as used in this rule have the following definitions:

A. ALLOCATION FACTORS

1. Transmission Wages and Salaries Allocation Factor shall equal the ratio of Transmission-related direct wages and salaries including those of affiliated Companies to the PTO's total direct wages and salaries including those of the Affiliates' Companies and excluding administrative and general wages and salaries.

2. PTF/HTF Transmission Plant Allocation Factor shall equal the ratio of PTF/HTF Transmission Plant to Total Investment in Transmission Plant, excluding capital leases in the Phase I/II HVDC-TF (Phase I/II HVDC-TF Leases).

3. Plant Allocation Factor shall equal the ratio of the sum of Total Investment in Transmission Plant, excluding Phase I/II HVDC-TF Leases, and Transmission Related Intangible and General Plant to Total Plant in service excluding Phase I/II HVDC-TF Leases.

B. TERMS

Administrative and General Expense shall equal the PTO's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928 and 930.1 and excluding Merger-Related Costs included in FERC Account Nos. 920-935 (other than those in FERC Account Nos. 924, 928 and 930.1, which have already been excluded).

Amortization of Loss on Reacquired Debt shall equal the PTO's expenses as recorded in FERC Account No. 428.1.

Amortization of Investment Tax Credits shall equal the PTO's credits as recorded in FERC Account No. 411.4.

Depreciation Expense for Transmission Plant shall equal the PTO's transmission expenses as recorded in FERC Account No. 403.

General Plant shall equal the PTO's gross plant balance as recorded in FERC Account Nos. 389-399.

General Plant Depreciation and Amortization Expense shall equal the PTO's general expenses as recorded in FERC Account No. 403 and NSTAR Electric's FERC Account No. 404 for items subject to amortization.

General Plant Amortization Reserve shall equal NSTAR Electric's general reserve balance as recorded in FERC Account No. 111.

HTF Transmission Plant shall equal the PTO's balance of investment in the Highgate Transmission Facilities as recorded in FERC Account Nos. 350-359.

Intangible Plant shall equal NSTAR Electric's gross plant balance as recorded in FERC Account No. 303. The only allowable Intangible Plant for inclusion are software, patent or rights costs.

Intangible Plant Amortization Expense shall equal NSTAR Electric's amortization expenses as recorded in FERC Account Nos. 404-405. The only allowable Intangible Plant Amortization Expense for inclusion is the amortization of software, patent or rights costs.

Intangible Plant Amortization Reserve shall equal NSTAR Electric's amortization reserve balance as recorded in FERC Account No. 111. The only allowable Intangible Plant Amortization Reserve for inclusion is that related to the amortization of software, patent or rights costs.

Maine Power Reliability Program Construction Work In Progress ("MPRP CWIP") shall equal Central Maine Power Company's ("CMP's") MPRP CWIP balance as recorded in FERC Account No. 107 for costs determined to be Pool- Supported PTF in accordance with Schedule 12 of this OATT.

Merger-Related Costs shall equal NSTAR Electric Company's ("NSTAR Electric"), CL&P's, Public Service Company of New Hampshire's ("PSNH") and WMECO's amortized merger-related costs as authorized by FERC or by state regulatory order.

New England East-West Solution Construction Work in Progress (“NEEWS CWIP”) shall equal the NEEWS CWIP balances of The Connecticut Light and Power Company (“CL&P”) and Western Massachusetts Electric Company (“WMECO”) and New England Power Company (“NEP”) as recorded in FERC Account No. 107 for costs determined to be Pool-Supported PTF in accordance with Schedule 12 of this OATT.

Other Regulatory Assets/Liabilities - FAS 106 shall equal the net of the PTO's FAS 106 balance as recorded in FERC Account 182.3 and any FAS 106 balance as recorded in the PTO's FERC Account No. 254.

Other Regulatory Assets/Liabilities - FAS 109 shall equal the net of the PTO's FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in the PTO's FERC Account No. 254.

Other Regulatory Assets/Liabilities - shall equal NSTAR Electric’s, CL&P’s, PSNH’s and WMECO’s unamortized balance of merger-related transmission costs recorded in FERC Account No. 182.3 as authorized by FERC.

Payroll Taxes shall equal those payroll expenses as recorded in the PTO's FERC Account Nos. 408.1.

Phase I/II HVDC-TF Leases shall equal the PTO's balance in capital leases as recorded in FERC Account Nos. 350-359 and FERC Account Nos. 389-399.

Plant Held for Future Use shall equal the PTO's balance in FERC Account No.105.

Prepayments shall equal the PTO’s prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal the PTO’s expenses as recorded in FERC Account No. 924.

PTF Transmission Plant shall equal the PTO’s transmission plant as defined in the Section II.49 of the OATT and determined in accordance with Appendix A of this Rule, which is entitled “Rules for Determining Investment To be Included in PTF.”

PTF/HTF Transmission Plant Investment shall equal the PTO's (a) PTF Transmission Plant plus (b) HTF Transmission Plant.

Total Accumulated Deferred Income Taxes shall equal the net of the PTO's deferred tax balance as recorded in FERC Account Nos. 281-283 and the PTO's deferred tax balance as recorded in FERC Account No. 190.

Total Loss on Reacquired Debt shall equal the PTO's expenses as recorded in FERC Account 189.

Total Municipal Tax Expense shall equal the PTO's municipal tax expenses as recorded in FERC Account Nos. 408.1.

Total Plant in Service shall equal the PTO's total gross plant balance as recorded in FERC Account Nos. 301-399.

Total Transmission Depreciation Reserve shall equal the PTO's transmission reserve balance as recorded in FERC Account 108.

Transmission Merger-Related Costs shall equal NSTAR Electric's, CL&P's, PSNH's and WMECO's amortized merger-related transmission costs as authorized by FERC.

Transmission Operation and Maintenance Expense shall equal the PTO's expenses as recorded in FERC Account Nos. 560, 561.5-561.8, 562-564 and 566-573, and shall exclude all Phase I/II HVDC-TF expenses booked to accounts 560 through 573 and expenses already included in Transmission Support Expense, as described in Section K which are included in FERC Account Nos. 560-573.

Transmission Plant shall equal the PTO's Gross Plant balance as recorded in FERC Account Nos. 350-359.

Transmission Plant Materials and Supplies shall equal the PTO's balance as assigned to transmission, as recorded in FERC Account No. 154.

II. CALCULATION OF TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirement shall equal the sum of the PTO's (A) Return and Associated Income Taxes (including the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP), (B) Transmission Depreciation and Amortization Expense, (C) Transmission Related Amortization of Loss on Reacquired Debt, (D) Transmission Related Amortization of Investment Tax Credits, (E) Transmission Related Municipal Tax Expense, (F) Transmission Related Payroll Tax Expense, (G) Transmission Operation and Maintenance Expense, (H) Transmission Related Administrative and General Expenses, (I) Transmission Related Integrated Facilities Charges, minus (J) Transmission Support Revenue, plus (K) Transmission Support Expense, plus (L) Transmission-Related Expense from Generators, plus (M) Transmission Related Taxes and Fees Charge, minus (N) Revenue for Short-Term service under the OATT, (O) Transmission Rents Received from Electric Property and (P) Transmission Revenues from MEPCO Grandfathered Transmission Service Agreements. The Incremental Return and Associated Income Taxes for Post-2003 PTF Investment for each PTO shall be calculated using the investment base components specifically identified in Section A. 1 of the formula below.

A. Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate. To calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP, Transmission Investment Base will only include Sections II.A. 1 .(a), (d), (e), (k), and (1) in the manner indicated.

1. Transmission Investment Base

The Transmission Investment Base will be the year end balances of(a) PTF/HTF Transmission Plant, plus (b) Transmission Related Intangible and General Plant, plus (c) Transmission Plant Held for Future Use, less (d) Transmission Related Depreciation and Amortization Reserve, less (e) Transmission Related Accumulated Deferred Taxes, plus (f) Transmission Related Loss on Re.acquired Debt, plus (g) Other Regulatory Assets/Liabilities, plus (h) Transmission Prepayments, plus (i) Transmission Materials and Supplies, plus (j) Transmission Related Cash Working Capital, plus (k) MPRP CWIP, plus (l) NEEWS CWIP.

(a) PTF Transmission Plant will equal the balance of the PTO's PTF Investment in (a) Transmission Plant plus (b) HTF Transmission Plant. This value excludes (i) the PTO's

Phase I/II HVDC-TF Leases, (ii) the portion of any facilities, the cost of which is directly assigned under Schedule 11 to the OATT, to the Transmission Customer or a Generator Owner or Interconnection Requester, (iii) the Pre-1997 PTF gross plant investment associated with leased facilities occupied by the Phase II section of the Phase I/II HVDC-TF. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment, Post2003 PTF Transmission Plant shall be separately identified.

(b) Transmission Related Intangible and General Plant shall equal the sum of the PTO's balance of investment in Intangible Plant and General Plant multiplied by the Transmission Wages and Salaries Allocation Factor and the PTF/HTF Transmission Plant Allocation Factor.

(c) Transmission Plant Held for Future Use shall equal the PTO's balance of Transmission-related Plant Held for Future Use multiplied by the PTF/HTF Transmission Plant Allocation Factor.

(d) Transmission Related Depreciation and Amortization Reserve shall equal the PTO's balance of Total Transmission Depreciation Reserve, plus the balance of Transmission Related Intangible Plant Amortization Reserve, Transmission Related General Plant Depreciation Reserve and Transmission Related General Plant Amortization Reserve. Transmission Related Intangible Plant Amortization Reserve, Transmission Related General Plant Depreciation Reserve and Transmission Related General Plant Amortization Reserve shall equal the product of the sum of Intangible Plant Amortization Reserve, General Plant Depreciation Reserve and General Plant Amortization Reserve, and the Transmission Wages and Salaries Allocation Factor. This sum shall be multiplied by the PTF/HTF Transmission Plant Allocation Factor. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment, Transmission Depreciation Reserve associated with Post-2003 PTF Investment shall equal the PTO's balance of Total Transmission Depreciation Reserve multiplied by the ratio of Post-2003 PTF Transmission Plant to Total Investment in Transmission Plant, excluding capital leases in the Phase I/II HVDC-TF Leases.

(e) Transmission Related Accumulated Deferred Taxes shall equal the PTO's electric balance of Total Accumulated Deferred Income Taxes, multiplied by the Plant Allocation

Factor, further multiplied by the PTF/HTF Transmission Plant Allocation Factor. To calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment, Transmission Related Accumulated Deferred Income Taxes associated with Post-2003 PTF Investment shall equal the PTO's balance of total property-related accumulated deferred income taxes as recorded in FERC accounts 281 and 282, multiplied by the ratio of Total Investment in Transmission Plant, excluding Phase I/II HVDC-TF Leases, to Total Plant in Service excluding Phase I/II HVDC-TF Leases, further multiplied by the ratio of Post-2003 PTF Transmission Plant to Total Investment in Transmission Plant, excluding Phase I/II HVDC-TF Leases.

(f) Transmission Related Loss on Reacquired Debt shall equal the PTO's electric balance of Total Loss on Reacquired Debt multiplied by the Plant Allocation Factor, further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

(g) Other Regulatory Assets/Liabilities shall equal the PTO's electric balance of any deferred rate recovery of FAS 106 expenses multiplied by the Transmission Wages and Salaries Allocation Factor, plus the PTO's electric balance of FAS 109 multiplied by the Plant Allocation Factor, plus NSTAR Electric's, CL&P's, PSNH's and WMECO's unamortized balance of merger-related transmission costs recorded in FERC Account No. 182.3 as authorized by FERC. This sum shall be multiplied by the PTF/HTF Transmission Plant Allocation Factor.

(h) Transmission Prepayments shall equal the PTO's electric balance of prepayments multiplied by the Transmission Wages and Salaries Allocation Factor and further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

(i) Transmission Materials and Supplies shall equal the PTO's electric balance of Transmission Plant Materials and Supplies, multiplied by the PTF/HTF Transmission Plant Allocation Factor.

(j) Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of the PTO's Transmission Operation and Maintenance Expense, Transmission Related Administrative and General Expense and Transmission Support Expense, to the extent that Transmission Support Expense exceeds Transmission Support Revenue included in Paragraph J of the formula.

(k) MPRP CWIP shall equal CMP's balance as recorded in FERC Account No. 107 for the MPRP as authorized by Commission order and in accordance with CMP's Accounting Procedures for MPRP CWIP. In order to calculate the Incremental Return and Associated Income Taxes for MPRP CWIP, MPRP CWIP shall be separately identified.

(l) NEEWS CWIP shall equal CL&P, WMECO and NEP’s balances as recorded in FERC Account No. 107 for the NEEWS as authorized by Commission order and in accordance with the companies’ respective Accounting Procedures for NEEWS CWIP. In order to calculate the Incremental Return and Associated Income Taxes for NEEWS CWIP, NEEWS CWIP shall be separately identified.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) the PTO's Weighted Cost of Capital, plus (b) Federal Income Tax plus (e) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon the capital structure at the end of each year and will equal the sum of (i), (ii), and (iii) below. The Cost of Capital Rate to be used in calculating the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP, shall only reflect item (iii) below and shall apply in the manner indicated below.

(i) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity of the PTO's long-term debt then outstanding and the ratio that long-term debt is to the PTO's total capital.

(ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of the PTO's preferred stock then outstanding and the ratio that preferred stock is to the PTO's total capital.

(iii) the return on equity component, shall be the product of the allowed ROE of the PTO's common equity and the ratio that common equity is to the PTO's total capital. For pre-

1997 and post-1996 assets, the ROE is 11.07%. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP, the incremental return on equity shall be the product of: (1) the PTO's incremental return on equity of 1.0% for plant investments associated with projects included in the RSP and placed in service by December 31, 2008 or otherwise permitted in Docket Nos. ER04-157, et al.; (2) any ROE incentive approved by the FERC under Order No. 679 for other plant investments and MPRP CWIP and NEEWS CWIP, provided that the total ROE for any project, including any such ROE incentives, shall be capped by the top of the applicable zone of reasonableness determined by FERC for the relevant period, and (3) the ratio that common equity is to the PTO's total capital) [1]

(b) Federal Income Tax shall equal

$$\frac{(A+[(C+B)/D])(FT)}{I\text{-}FT}$$

where FT is the Federal Income Tax Rate and A is the sum of the preferred stock component and the return on equity component, as determined in Sections ll.A.2.(a)(ii) and (iii) above, B is Transmission Related Amortization of Investment Tax Credits, as determined in Section II.D., below, C is the Equity AFUDC component of Transmission Depreciation Expense, as defined in Section ll.B., and D is Transmission Investment Base, as determined in Section II.A.1., above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP, the incremental Federal Income Tax shall equal

$$\frac{(A' * FT)}{(1 - FT)}$$

where FT is the Federal Income Tax Rate and A' is the incremental return on equity component, as determined in Section II.A.2.(a)(iii) above.

(c) State Income Tax shall equal

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[1] FERC Form-730 contains a list of transmission projects for which FERC has granted incentives under Order No. 679.

$$\frac{(A+[(C+B)/D] + \text{Federal Income Tax})(ST)}{1 - ST}$$

where ST is the State Income Tax Rate, A is the sum of the preferred stock component and return on equity component determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section ll.D.below, C is the equity AFUDC component of Transmission Depreciation Expense, as defined in Section II.B.. D is the Transmission Investment Base, as determined in II.A.1., above and Federal Income Tax is the rate determined in Section II.A.2.(b) above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP, the incremental State Income Tax shall equal

$$\frac{(A' + \text{Federal Income Tax})(ST)}{(1 - ST)}$$

where ST is the State Income Tax Rate, A' is the incremental return on equity component determined in Section II.A.2.(a)(iii) above, and Federal Income Tax is the rate determined in Section II.A.2.(b) above.

B. Transmission Depreciation and Amortization Expense shall equal the PTF/HTF Transmission Plant Allocation Factor, multiplied by the sum of (i) the PTO's Depreciation Expense for Transmission Plant, plus (ii) an allocation of Intangible Plant Amortization Expense and (iii) General Plant Depreciation and Amortization Expense calculated by multiplying the sum of (a) Intangible Plant Amortization Expense and (b) General Plant Depreciation and Amortization Expense by the Transmission Wages and Salaries Allocation Factor.

C. Transmission Related Amortization of Loss on Reacquired Debt shall equal the PTO's electric Amortization of Loss on Reacquired Debt multiplied by the Plant Allocation Factor, and further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

D. Transmission Related Amortization of Investment Tax Credits shall equal the PTO's electric Amortization of Investment Tax Credits multiplied by the Plant Allocation Factor, and further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

E. Transmission Related Municipal Tax Expense shall equal the PTO's total electric municipal tax expense multiplied by the Plant Allocation Factor, and further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

F. Transmission Related Payroll Tax Expense shall equal the PTO's total electric payroll tax expense, multiplied by the Transmission Wages and Salaries Allocation Factor, further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

G. Transmission Operation and Maintenance Expense shall equal the PTO's Transmission Operation and Maintenance Expenses multiplied by the PTF/HTF Transmission Plant Allocation Factor.

H. Transmission Related Administrative and General Expenses shall equal the sum of the PTO's (1) Administrative and General Expenses multiplied by the Transmission Wages and Salaries Allocation Factor, (2) Property Insurance multiplied by the Transmission Plant Allocation Factor, and (3) Expenses included in Account 928 (excluding Merger-Related Costs included in Account 928) related to FERC Assessments multiplied by Plant Allocation Factor, plus any other Federal and State transmission related expenses or assessments, plus specific transmission related expenses included in Account 930.1 plus Transmission Merger-Related Costs. This sum shall be multiplied by the PTF/HTF Transmission Plant Allocation Factor.

I. Transmission Related Integrated Facilities Charges shall equal the PTO's transmission payments to Affiliates for use of the PTF and HTF integrated transmission facilities of those Affiliates.

J. Transmission Support Revenues shall equal the PTO's revenue received for PTF and HTF transmission support but excluding the support payments to PTOs or their designee pursuant to Schedule 11 and excluding the support payments to PTOs or their designee pursuant to Schedule 12 Part 1(a) and Part B.2, and excluding support payments, if any, made to PTOs or their respective designee pursuant to Part II.C of this OATT.

K. Transmission Support Expense shall equal the expense paid by (1) PTOs, (2) Transmission Customers or (3) Related Persons pursuant to Section II.49 of the Tariff for PTF and HTF transmission support other than expenses for payments made for congestion rights or for transmission facilities or facility upgrades placed in service on or after January 1, 1997, where the support obligation is required to be borne by particular PTOs or other entities in accordance with the OATT. Transmission Support Expenses by any entity other than a PTO, included in this provision, shall be capped at that entity's annual payment for Regional Network Service or its Point To Point Service for each individual Point To Point transaction from the resource with which the support payment is associated.

L. Transmission-Related Expense from Generators shall equal the expenses from generators that both (1) the PTO Administrative Committee determines should be included as transmission expense as a result of the impact of such generators on reducing transmission costs that would otherwise be required to be paid by Transmission Customers and (2) are reflected in a filing made by the PTOs with the Commission under Section 205 of the Federal Power Act and accepted by the Commission for recovery under the OATT.

M. Transmission Related Taxes and Fees Charge shall include any fee or assessment imposed by any governmental authority on service provided under this Section which is not specifically identified under any other section of this rule.

N. Revenues for Short-Term service under the OATT shall be revenues distributed to each PTO for short term service provided under the OATT, received after March 1, 1999. These revenues will be credited pro-rata between pre-1997 and post-1996 PTF revenue requirements in proportion to pre-1997 and post-1996 PTF Transmission Plant.

O. Transmission Rents Received from Electric Property shall equal any Account 454 Rents from electric property, associated with PTF and HTF Transmission Plant as defined in Section II.A.1.(a) above but not reflected as a credit in Transmission Support Revenues in paragraph K of this Attachment.

P. Transmission Revenues from MGTSAs shall equal any MGTSA revenues recorded in Account 456.

APPENDIX A TO ATTACHMENT F
IMPLEMENTATION RULE RULES FOR DETERMINING
INVESTMENT TO BE INCLUDED IN PTF

Section A – Transmission Lines*

Section B – Terminal Facilities*

Section C – Right of Way*

Effective June 1, 1998

*The following provision shall apply to Sections A, B and C below:

Of those transmission facilities that are upgrades, modifications or additions to the New England Transmission System on and after January 1, 2004, only those that: (i) are rated 115kV or above, and (ii) otherwise meet the non-voltage criteria specified in Section II.49 of this OATT shall be classified as PTF. Those transmission facilities that were PTF on December 31, 2003, and any upgrades to such facilities that meet the definition of PTF specified in this OATT, shall remain classified as PTF for all purposes under the Transmission, Markets and Services Tariff.

Section A: Rules for Determining Transmission Line Investment to be Included in PTF

Pool Transmission Facilities (PTF) are the transmission facilities owned by PTO rated 69 kV or above required to allow energy from significant power sources to move freely on the New England transmission network, and include:

1. All transmission lines and associated facilities owned by the PTOs rated 69 kV and above, except:

    a. those which are required to serve local load only, thereby contributing little or no parallel capability to the transmission network,

    b. generator leads, which are defined as the radial transmission from a generator bus to the nearest point on the transmission network,

c. lines that are normally operated open.

d. those that are classified as MTF.

2. Terminal facilities (including substation facilities such as transformers, circuit breakers, and associated equipment) required to interconnect the lines which constitute PTF (see Section B).
3. If a PTO with significant generation in its system (initially 25 MW) is connected to the New England Transmission System and none of the transmission facilities owned by the PTO qualify to be included in PTF as defined in "1" and "2" above, then such PTO's connection to PTF will constitute PTF if both of the following requirements are met for this connection:

   a. The connection is rated 69 kV or above.

   b. The connection is the principal transmission link between the PTO and the remainder of the ISO PTF network.

The PTF facilities covered by this provision shall consist of a single line from the point of connection on the transmission network to the first bus within the PTO's system.

4. R/W and land required for the installation of PTF facilities listed in "1", "2", or "3" (see Section C).

The following examples indicate the intent of the above definitions:

a. Radial tap lines to local load are excluded.

b. Lines which loop, from two geographically separate points on the transmission network, the supply to the load bus from the transmission network are included.

c. Lines which loop, from two geographically separate points on the transmission network, the connections between a generator bus, and the transmission network are included.

d. Radial connection or connections from a generating station to a single substation or switching station on the transmission network are excluded unless the requirements of paragraph 3 above are met.

e. The cost of a PTF line will include only those costs associated with that line. When other facilities require rebuilding or undergrounding to permit the construction of a PTF facility, the investment costs in the relocated or undergrounded facility will not be included.

f. Where multiple circuit structures support a mixture of PTF and Non-PTF circuits, the total cost of the multiple circuit structures will be allocated between the circuits in accordance with the ratio of costs of comparable individual structures.

The PTOs shall review at least annually the status of transmission lines and related facilities and determine whether such facilities constitute PTF and shall prepare and keep current a schedule or catalog of PTF facilities.

All new facilities being installed should be properly classified at the time the facilities are approved under Section I.3.9 of the Transmission, Markets and Services Tariff.

Transmission facilities owned or supported by a Related Person of a PTO which are rated 69 kV or above and are required to allow Energy from significant power sources to move freely on the New England Transmission System shall also constitute PTF provided (i) such Related Person files with the ISO its consent to such treatment; and (ii) the ISO determines in consultation with the PTO Administrative Committee determines that treatment of the facility as PTF will facilitate accomplishment of the ISO's objectives. If such facilities constitute PTF pursuant to this paragraph, they shall be treated as "owned" or "supported," as applicable, by a PTO for purposes of the OATT and the other provisions of the TOA, including the ability to include the cost associated with such PTF and any Transmission Support Expenses for support of PTF made by its Related Person in that PTO's Annual Transmission Revenue Requirements pursuant to Attachment F of the OATT.

Section B: Rules for Determining Terminal Investment to be Included in PTF

Terminal Investment is investment associated with the terminal facilities of electrical lines, including substation facilities such as transformers, circuit breakers, disconnects and airbreaks, bus conductor, related protection equipment and other related facilities (see paragraph 7).

1. The investment in terminal facilities shall be included where these facilities are identifiable and serve directly for terminating and/or switching PTF lines.

2. In cases where a line terminal is used in conjunction with both PTF and Non-PTF lines and/or facilities, it will be considered a PTF facility providing the terminal facility is at 69 kV or above and carries any power flow at 69 kV or above through parallel paths within the interconnected network under normal operation. PTF equipment is any element of the transmission system in those parallel paths. Any equipment not in these parallel paths is Non-PTF.

3. Where line terminals are installed solely for Non-PTF facilities, and do not carry any power flow at 69 kV or above through parallel paths within the interconnected network under normal operation, such terminal cost shall not be included in PTF.

4. A two-winding transformer which connects PTF facilities at both terminals along with any switcher which can be identified as pertaining solely to the transformer, will be included in their entirety as PTF.

5. An autotransformer or three winding transformer which connects PTF facilities at two (2) or more terminals, along with any switchgear which can be identified as pertaining solely to the PTF-connected terminals of the transformer, will be included in their entirety as PTF. An autotransformer or three winding transformer which is connected to PTF at only one terminal will not be PTF.

6. When a transformer supplies only Non-PTF facilities, the entire transformer installation, including the high side disconnect switch or circuit breaker and associated structures or tap lines shall be excluded from PTF except for the portion of line terminal facilities covered by paragraph 2.

7. Other facilities – the investment in that portion of a multi-use substation or switching station which is identifiable as serving a PTF function shall be included in PTF, while the investment in

such facilities which are identifiable as serving a Non-PTF function shall be excluded. The investment in land, structures, ground mats, fences, ducts, lighting, etc., can often be identified and thus allocated. The investment in other facilities in the substation or switching station, excluding transformers, which are not identifiable as serving either a PTF or a Non-PTF function and general overheads shall be allocated to PTF on the basis of the ratio of the investment in those facilities identified as PTF to the sum of the investments in the facilities which are identified as serving PTF and Non-PTF functions; the equipment cost of power transformers shall not be included in this calculation for determining the division of investment, since this would produce a distorted balance.

8. Alternate method of allocating the cost of terminal facilities – In those cases where the major portion of the investment has been lumped and utility plant records do not permit the accurate assignment of costs to specific terminals, the total investment may be prorated to PTF and Non-PTF according to the number of terminals serving PTF and Non-PTF facilities.

9. In cases where microwave facilities are used in whole or part for PTF purposes, a prorated portion of such investment shall be included in PTF based on the PTF and Non-PTF functions served by the microwave facilities except where these facilities are otherwise supported under the Microwave Sharing Agreement dated June 1, 1970 among some of the New England utilities.

10. Generator unit transformers and generator circuit breakers shall be excluded from PTF, unless otherwise included by paragraphs 1 or 5.

11. In cases where remote control (Supervisory Control) and telemetering facilities are used in whole or in part for PTF purposes, a prorated portion of such investment shall be included in PTF based on the PTF and Non-PTF functions served by these facilities.

12. The PTO Administrative Committee may designate appropriate facilities as PTF.

Section C: Rules for Determining PTF R/W Costs

1. If a R/W has only PTF lines and no Non-PTF lines are expected to be added, the entire cost of the R/W is to be included as PTF.

2. If the R/W has only PTF lines but includes additional unused R/W which was purchased for future use by Non-PTF lines, the cost of the additional R/W is not to be included as PTF.

3. If the R/W contains both PTF and Non-PTF lines, the R/W cost to be assigned to PTF is to be determined as follows:

   a. Where new or additional R/W is required to permit the construction of PTF line(s) and the added R/W is adequate to contain the new PTF, the cost of the new R/W is to be assigned to the PTF line(s), (even if the PTF line is located on the old R/W).

   b. Where an existing R/W is used (without additional R/W), the amount allocated to PTF will be determined in accordance with paragraph 4.

   c. Where a R/W is widened, but the new facilities, either PTF or Non-PTF, require partial use of the existing R/W, the incremental cost of the new R/W will be assigned to the new facilities. The width of the original R/W will be added to the width of the new R/W and the combined width will be allocated between PTF and Non-PTF as in paragraph 4. The cost of the old R/W and the combined width will be allocated between PTF and Non-PTF as in paragraph 4. The cost of the old R/W will be allocated to the new facilities in proportion to the width of the old R/W assigned to the new facilities. Thus, the R/W for the new facilities will be the additional R/W plus a share of the old R/W.

4. In allocating R/W between PTF and Non-PTF lines, each shall bear a share of the R/W in accordance with the following formulae.

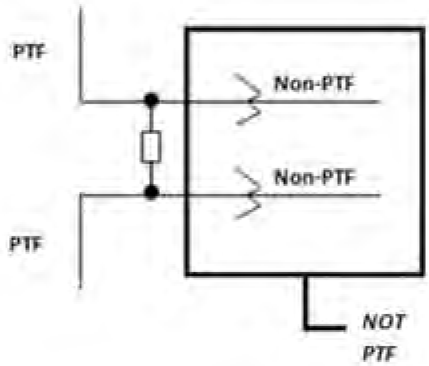
   a. Determine the R/W width required for each facility if constructed independently using appropriate type structures.

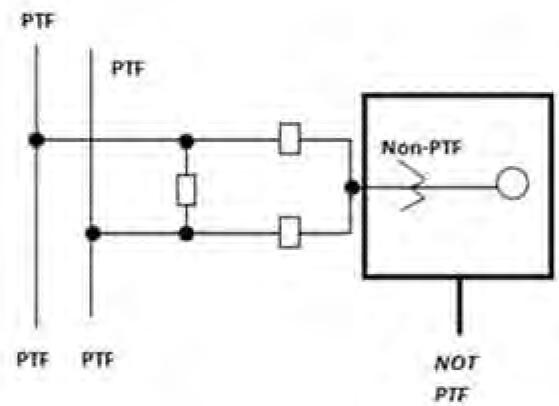
   b. Allocate the actual R/W width to each facility in the proportion its independent R/W requirement would be to the sum of the independent R/W requirements.

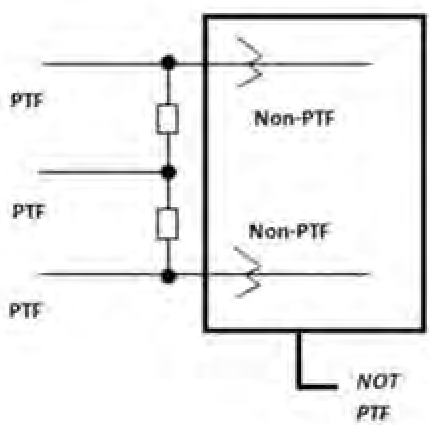
5. R/W and land held for future PTF facilities may be included in PTF facilities only if specifically approved by the PTO Administrative Committee included under paragraph 1.

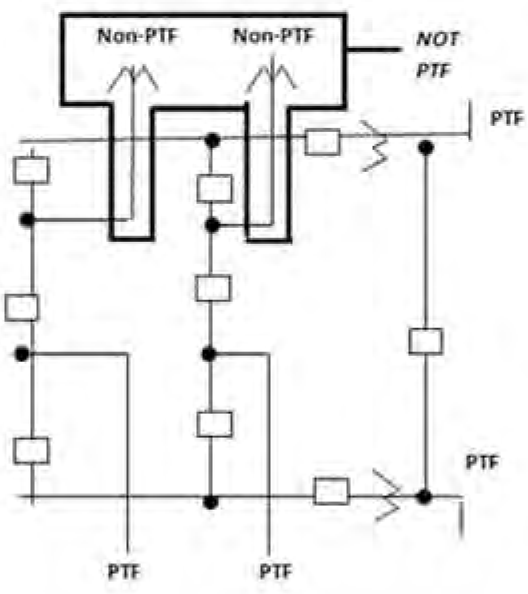
ATTACHMENT 1 TO APPENDIX A TO
ATTACHMENT F IMPLEMENTATION RULE

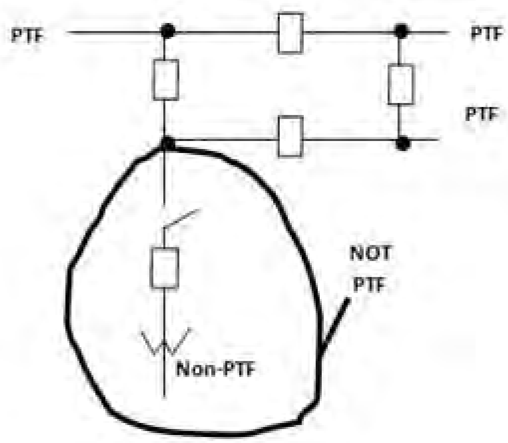
Examples of the Methods for Distinguishing PTF
from Non-PTF Terminal Facilities
in a Number of Typical Substation Configurations







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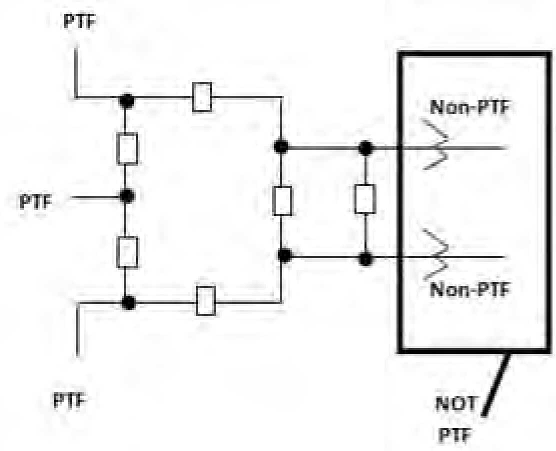
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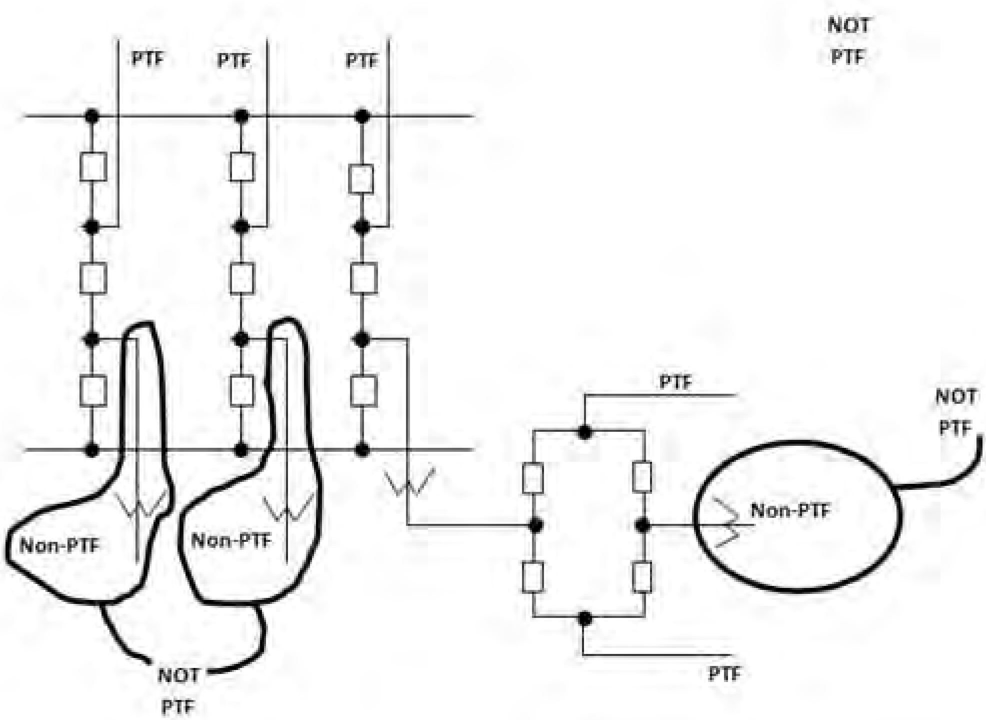
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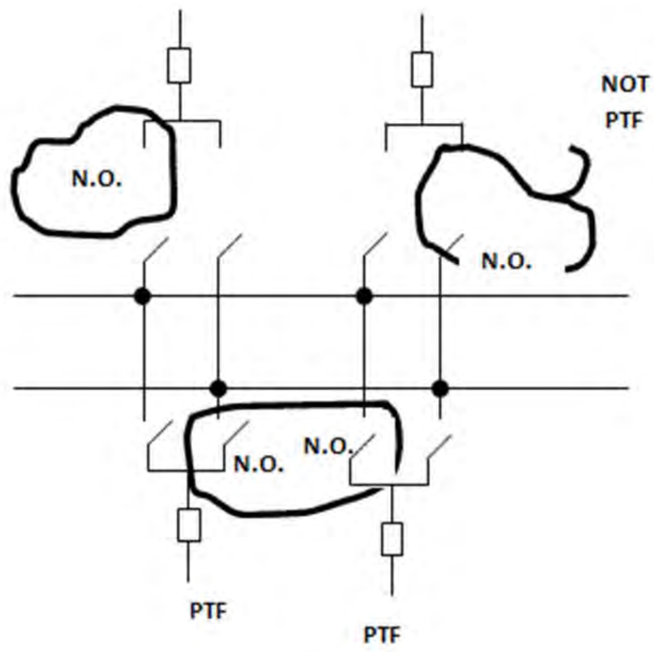
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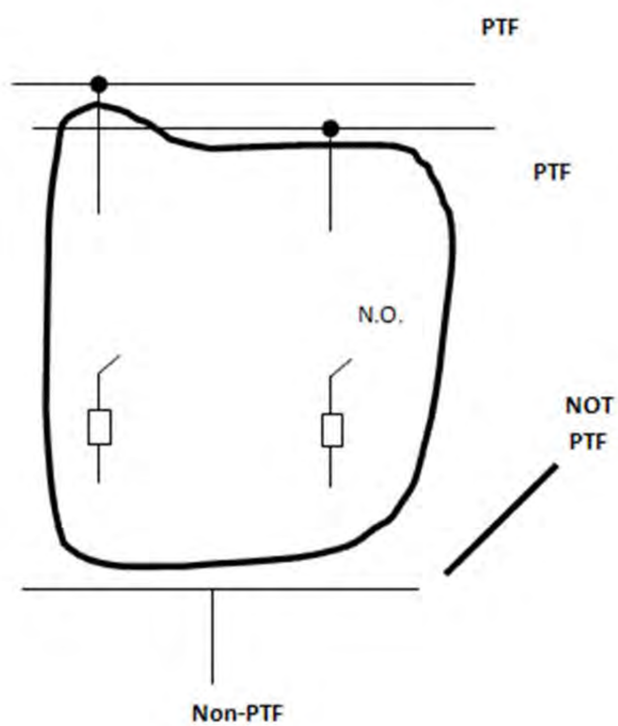
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APPENDIX B TO ATTACHMENT F IMPLEMENTATION RULE
HTF TRANSITION SCHEDULE

The inclusion of HTF Annual Transmission Revenue Requirements in Attachment F (and the calculation of the Pool PTF Rate) to this OATT will be limited by the provisions of this schedule.

VELCO, as a PTO and acting as agent for the HTF owners, may include the HTF Annual Transmission revenue Requirements (i.e., HTF Transmission Plant) within the Attachment F calculations. Additionally, the total HTF Annual Transmission Revenue Requirements included shall be limited to the following:

Year 1: A maximum of $1.2M in Year 1. For the sole purpose of this Schedule, “Year 1” shall be defined as the first full year after the Operations Date:

Year 2: A maximum of $2.0M in Year 2. For the sole purpose of this Schedule, “Year 2” shall be defined as the second full year after the Operations Date;

Year 3: A maximum of $2.8M in Year 3. For the sole purpose of this Schedule, “Year 3” shall be defined as the third full year after the Operations Date;

Year 4: A maximum of $3.5M in Year 4. For the sole purpose of this Schedule, “Year 4” shall be defined as the fourth full year after the Operations Date;

and

Year 5 and thereafter: All HTF Annual Transmission Revenue Requirements shall be included in Attachment F.

ATTACHMENT F IMPLEMENTATION RULE
APPENDIX C

I. DEFINITIONS

(i) **Annual True-up – Pre-1997 (ATU):** shall be the difference between the actual Pre-1997 Annual Transmission Revenue Requirements and the as-billed Pre-1997 Annual Transmission Revenue Requirements, adjusted to include interest pursuant to Part II below. The actual Pre-1997 Annual Transmission Revenue Requirements shall be an after-the-fact calculation and shall be determined at the conclusion of each rate-effective period, i.e. June 1 through May 31 of each year, by application of the Attachment F formula rate and each PTO’s relevant Pre-1997 PTF cost data for the most recently concluded calendar year. The as-billed Pre-1997 Annual Transmission Revenue Requirements shall be those Pre-1997 Annual Transmission Revenue Requirements used to establish the RNS rates that were made effective on June 1 of the most recently concluded calendar year.

(ii) **Annual True-up – Post-1996 (ATU’):** shall be the difference between the actual Post-1996 Annual Transmission Revenue Requirements and the as-billed Post-1996 Annual Transmission Revenue Requirements, adjusted to include interest pursuant to Part II below. The actual Post-1996 Annual Transmission Revenue Requirements shall be an after-the-fact calculation and shall be determined at the conclusion of each rate-effective period, i.e. June 1 through May 31 of each year, by application of the Attachment F formula rate and each PTO's relevant Post-1996 PTF cost data for the most recently concluded calendar year.The as-billed Post-1996 Annual Transmission Revenue Requirements shall be those Post-1996 Annual Transmission Revenue Requirements used to establish the RNS rates that were made effective on June 1 of the most recently concluded calendar year and which included the sum of the Post-1996 Transmission Revenue Requirements for the year prior to the most recently concluded calendar year plus the Forecasted Transmission Revenue Requirements for the most recently concluded calendar year.

(iii) Forecast Period: The calendar year immediately following the calendar year for which the most recent FERC Form 1 data is available.

(iv) Forecasted Transmission Plant Additions (FTPA): shall equal an estimate of the PTO's Post-1996 PTF plant additions for the Forecast Period.

(v) Forecasted MPRP CWIP (FCWIP): shall equal CMP's estimated incremental change in MPRPCWIP for the Forecast Period.

(vi) Carrying Charge Factor (CCF): shall reflect the most recent calendar year data used in determining Post-1996 Annual Transmission Revenue Requirements and shall equal the sum of Attachment F Sections II.A, excluding MPRP CWIP and NEEWS CWIP, through II.H divided by Attachment F Section II.A.1.a.

(vii) MPRP Cost of Capital Rate (MCOC): shall be determined in accordance with Attachment F Section II.A.2.

(viii) Forecasted Transmission Revenue Requirement (FTRR): shall equal FTPA multiplied by the CCF plus FCWIP multiplied by the MCOC, plus FCCWIP multiplied by CCOC, plus FWCWIP multiplied by WCOC, plus FNCWIP multiplied by NCOC, as shown:

FTRR = FTPA * CCF + (FCWIP * MCOC) + (FCCWIP * CCOC) + (FWCWIP * WCOC) + (FNCWIP * NCOC)

(ix) Forecasted CL&P NEEWS CWIP (FCCWIP): shall equal CL&P's estimated incremental change in NEEWS CWIP for the Forecast Period.

(x) Forecasted WMECO NEEWS CWIP (FWCWIP): shall equal WMECO's estimated incremental change in NEEWS CWIP for the Forecast Period.

(xi) NEEWS CL&P Cost of Capital Rate (CCOC): shall be determined in accordance with Attachment F Section II.A.2.

(xii) NEEWS WMECO Cost of Capital Rate (WCOC): shall be determined in accordance with Attachment F Section II.A.2.

(xiii) Forecasted NEP NEEWS CWIP (FNCWIP): shall equal NEP's estimated incremental change in NEEWS CWIP for the Forecast Period.

(xiv) NEEWS NEP Cost of Capital Rate (NCOC): shall be determined in accordance with Attachment F Section II.A.2.

II. INTEREST ON ANNUAL TRUE-UPS

Interest on the Annual True-up amounts (i.e., interest applicable to any over or under collection) shall be calculated in accordance with the methodology specified in the Commission's regulations at 18 C.F.R. § 35.19a (a) (2) (iii).

III. INFORMATIONAL FILINGS

The PTOs' annual informational filing shall include supporting documentation for their estimated capital additions to be placed in service during the current calendar year as well as supporting documentation pertaining to any annual true-up and interest calculations.

SCHEDULE 1

SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE

Scheduling, System Control and Dispatch Service is the service required to schedule at the regional level the movement of power through, out of, within, or into the New England Control Area. Local level service is provided by the PTOs under Schedule 21 to this OATT. For transmission service under this OATT, this Ancillary Service can be provided only by the ISO and the Transmission Customer must purchase this service from the ISO. Charges for Scheduling, System Control and Dispatch Service are to be based on the expenses incurred by the ISO, and by the individual PTOs in the operation of Local Control Center dispatch centers or otherwise, to provide these services. The expenses incurred by the ISO in providing these services recovered under Section IV of the OATT. A surcharge for the expenses incurred by PTOs in the provision of these services for transmission service over the PTF will be added to the Through or Out Service rate and to the Regional Network Service rate. Any Scheduling, System Control and Dispatch Service expenses for the provisions of these services for MTF Service shall be determined separately and assessed to Transmission Customers receiving MTF Service, in accordance with the arrangements between the Transmission Customers receiving MTF Service and the MTF Provider.

The expenses incurred in providing Scheduling, System Control and Dispatch Service for transmission service over the PTF for each PTO will be determined by an annual calculation based on the previous calendar year's data as shown, in the case of PTOs which are subject to the Commission's jurisdiction, in the PTO's FERC Form 1 report for that year, and shall be based on actual data in lieu of allocated data if specifically identified in the Form 1 report. The surcharge shall be redetermined annually as of June 1 in each year and shall be in effect for the succeeding twelve (12) months. The rate surcharge per kilowatt for each month is one-twelfth of the amount derived by dividing the total annual PTO expenses for providing the service by the sum of the average of the coincident Monthly Peaks (as defined in Section II.21.2) of all Local Networks for the prior calendar year.

Each Transmission Customer which is obligated to pay the rate for Regional Network Service for a month shall pay the surcharge on the basis of the number of kilowatts of its Monthly Network Load (as defined in Section II.21.2 of this OATT) for the month. Each Transmission Customer which is obligated to pay the rate for Through or Out Service for the applicable period shall pay the surcharge on the basis of the highest amount of its Reserved Capacity for each transaction scheduled as Through or Out Service for such period.

The details for implementation of Schedule 1 for transmission service over the PTF shall be established in accordance with the Implementation Rule for Schedule 1 attached to this OATT.

SCHEDULE 1 IMPLEMENTATION RULE

This rule provides detail with respect to the calculation of the rate surcharge each year for Scheduling, System Control and Dispatch Service, which is defined in the OATT as the service required to schedule the movement of power through, out of, within, or into the New England Control Area over Pool Transmission Facilities ("PTF"). This service also includes the dispatch and security analysis of the system. Scheduling, System Control and Dispatch Service for transmission service over transmission facilities other than PTF is provided under Schedule 21 of the OATT. For transmission service under the OATT, this Ancillary Service will be provided by the ISO, and rates collected under Schedule 1 are based on expenses incurred by the Local Control Centers, and the PTOs (as described herein) in providing the necessary elements of this service to the ISO. All of the costs of the ISO for the provision of service under Schedule 1 will be recovered under Section IV of the Transmission, Markets and Services Tariff. Schedule 1 of the OATT is for collection only of the revenue requirements for Local Control Centers and PTOs for System Control and Dispatch Service. Any Transmission Customer taking Regional Network Service or Through or Out Service shall be subject to the rate surcharge calculated under Schedule 1 of the OATT as described in more detail in this rule below.

The PTOs shall make an annual informational filing on or before July 31 of each year showing the Schedule 1 rate surcharge to be utilized by the ISO in the billing of Schedule 1 Ancillary Service that will be in effect for the period beginning June 1 of that year through May 31 of the subsequent year. If there are any corrections made to the information reflected in the informational filing after it has been submitted, the PTOs would file corrections to the informational filing. At least thirty (30) days before the informational filing is made with the Commission, the PTOs shall make available to Transmission Customers and any other interested parties a draft of the proposed filing for review and comment prior to the filing by posting such draft on the RTO NE website. The filing of the informational filing does not reopen the formula rate set forth below for review, but rather is contestable only with respect to the accuracy of the information contained in the informational filing. The ISO shall have the discretion to conduct audits of such charges, with advisory Stakeholder input on the scope of audit, including on any agreed-upon procedures to be used by the auditor. In this provision, the term "agreed-upon procedures" shall have the meaning afforded to it by the American Institute of Certified Public Accountants.

I. DEFINITIONS

Capitalized terms used in this rule that are not defined in the Tariff have the following definitions:

Scheduling and Dispatch Surcharge Rate shall equal the rate surcharge that is determined for the applicable period beginning on June 1, 1999, in accordance with Section II of this rule below.

PTF Transmission-Related Local Control Center Scheduling and Dispatch Expense shall equal the PTF transmission related expenses incurred by the PTO from REMVEC II, CONVEX/ESCC, and the Maine Local Control Center as recorded in each PTO's FERC Form 1, Account Nos. 561-561.4, excluding any charges recorded in this account that were incurred under the OATT or Schedule 21 of the OATT. The expenses shall be net of any revenues, as reflected in FERC Account No. 456, received by the PTO for providing scheduling and dispatch services, excluding any revenues recorded in this account that where received as a result of charges under the OATT.

REMVEC II is a Local Control Center of the ISO providing security analysis of PTF.

Local PTF Transmission-Related Scheduling and Dispatch Expense shall equal the sum of (1) each PTO's expenses as recorded in FERC Account Nos. 561-561.4, excluding any ISO and Local Control Center related expenses and any expenses recorded in these accounts, that were incurred under this OATT or the Schedule 21 of this OATT of each PTO as a Transmission Customer, multiplied by the PTF Transmission Plant Allocator, (2) NSTAR Electric Company SCADA-related expenses as calculated in accordance with Appendix A of this Rule, (3) the Central Maine Power Company Local Control Center revenue requirements as calculated in accordance with Appendix B of this Rule, and (4) the CL&P Dispatch Center Revenue Requirement as calculated in accordance with Appendix C of the Rule.

PTF Transmission Plant Allocation Factor is the factor for allocating transmission costs and expenses between PTF and Non-PTF as determined for the applicable period pursuant to Attachment F of the OATT.

II. CALCULATION OF THE SCHEDULING AND DISPATCH SURCHARGE

A. Surcharge for Regional Network Service Customers

For Network Customers, the scheduling and dispatch surcharge for Regional Network Service shall equal the Network Customer's Regional Monthly Network Load, as defined in Section II.21.2 of the OATT,

multiplied by the Monthly Scheduling and Dispatch Surcharge Rate as determined in accordance with Section II.C below.

B. <u>Surcharge for Through or Out Customers</u>

For Through or Out Service Customers, the Scheduling and Dispatch Surcharge shall equal the Transmission Customer’s Reserved Capacity for each transaction scheduled for the month multiplied by the applicable Monthly or Hourly Scheduling and Dispatch Surcharge Rate, as determined in accordance with Section II.C below.

C. <u>Scheduling and Dispatch Surcharge Rate</u>

The Scheduling and Dispatch Surcharge Rate will be the surcharge rate in effect from time to time for the applicable period, determined pursuant to the formula described below based on the prior calendar year’s data. The Scheduling and Dispatch Surcharge Rate shall be redetermined each year, with the new Surcharge Rate going into effect on June 1 of each year, and be effective for the succeeding twelve months.

In the case of PTOs which are subject to the Commission’s jurisdiction, the data used shall be as identified in the PTO’s FERC Form 1 report for that year, and shall be based on actual data in lieu of allocated data if specifically identified in the FERC Form 1. When FERC Form 1 data is not the direct source of the data used in the formula, the worksheets used to develop the inputs will reflect Appendix A, Appendix B, and Appendix C of this Rule.

The Scheduling and Dispatch Surcharge Rate shall be equal to the sum of (1) PTF Transmission-Related Local Control Center Scheduling and Dispatch Expense, (2) Local PTF Transmission Related Scheduling and Dispatch Expense, (3) less Schedule 1 revenues from the prior year surcharges for Short-Term Point-To-Point Transactions, and divided by the annual average of the sum of all Regional Network Customers Monthly Peak Load, as defined in Section II.21.2 of the OATT, from the prior calendar year plus the Long-Term Firm Point-To-Point Service Reserved Capacity, from the prior calendar year.

The Monthly Scheduling and Dispatch Surcharge Rate shall equal one-twelfth of the Scheduling and Dispatch Surcharge Rate.

<u>The Hourly Scheduling and Dispatch Surcharge Rate</u> shall be the annual rate divided by 8760.

APPENDIX A TO SCHEDULE 1 IMPLEMENTATION RULE

NSTAR ELECTRIC COMPANY SCADA

This service is required to schedule the movement of power through, out of, within, or into the New England Control Area over Pool Transmission Facilities (PTF). Service under this schedule represents the contribution to that service provided by the PTO's own Dispatch Center, commonly referred to as SCADA. These costs are excluded from costs in Attachment F.

The PTF Revenue Requirement for the scheduling, system control and dispatch service that is based on data for the calendar year 2004 or later shall include an allocated PTF-related amount of Incremental Return and Associated Income Taxes on SCADA-related transmission plant investments included in the Regional System Plan and placed in-service on or after January 1, 2004 (such investments referred to herein as "Post-2003 Dispatch Center Investment"). The Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment shall reflect a surcharge of a 100 basis point ROE adder applicable to certain investment base components as specified in the formula below. The data used in determining the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment shall be based on actual data in lieu of allocated data if specifically identified in NSTAR Electric's accounting records.

Definitions: Dispatch Center Wages and Salaries Allocation Factor: Ratio of Dispatch Center Related Direct Wages and Salaries to NSTAR Electric's total Direct Wages and Salaries excluding Administrative and General Wages and Salaries.

Dispatch Center Plant Allocation Factor: Ratio of Total Investment in Dispatch Center Plant plus Dispatch Center Related General Plant, to Total Plant in service.

Dispatch Center Transmission Plant Allocation Factor: Ratio of Total Investment in Dispatch Center Plant plus Dispatch Center Related General Plant, to Total Investment in Transmission Plant.

The PTF Revenue Requirement for the Scheduling System Control and Dispatch Service shall equal the sum of the PTO's: (A) Return and Associated Income Taxes (including the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment), (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Related Amortization of Investment Tax Credits, (D) Dispatch Center

Related Municipal Tax Expense, (E) Dispatch Center Related Payroll Tax Expense (F) Dispatch Center Operation and Maintenance Expense, and (G) Dispatch Center Related Administrative and General Expense; multiplied by the PTF Transmission Plant Allocation Factor.

The Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment shall be calculated using the Dispatch Center investment base components specifically identified in Section A.1 of the formula below.

A. <u>Return and Associated Income Taxes</u> shall equal the product of the Dispatch Center Investment Base and the Cost of Capital Rate. To calculate the Incremental Return and Associated Income Taxes for Post–2003 Dispatch Center Investment, the Dispatch Center Investment Base will only include items (a), (d) and (e) under Section (A)(1), calculated in the manner indicated.

1. **<u>The Dispatch Center Investment Base</u>** will consist of (a) Dispatch Center Plant in FERC accounts 350-359, plus (b) Dispatch Center Related General Plant, plus (c) Dispatch Center Plant Held for Future Use, less (d) Dispatch Center Related Depreciation Reserve, less (e) Dispatch Center Related Accumulated Deferred Taxes, plus (f) Other Regulatory Assets, plus (g) Dispatch Center Prepayments, plus (h) Dispatch Center Materials and Supplies, plus (i) Dispatch Center Related Cash Working Capital.

a. <u>Dispatch Center Plant</u> will equal the year-end balance of the PTO's Investment in Dispatch Center per FERC accounts 350 through 359. Dispatch Center Plant Investment is not included in PTF investment in the Attachment F revenue requirement. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, Post-2003 Dispatch Center Plant shall be separately identified.

b. <u>Dispatch Center Related General Plant</u> shall equal the PTO's year-end balance of Investment in General Plant multiplied by the Dispatch Center Wages and Salaries Allocation Factor described above.

c. <u>Dispatch Center Plant Held for Future Use</u> shall equal the year-end balance of Transmission related Dispatch Center Investment in FERC account 105.

d. <u>Dispatch Center Related Depreciation Reserve</u> shall equal the year-end balance of Transmission Dispatch Center Depreciation Reserve, plus the year-end balance of

Dispatch Center Related General Depreciation Reserve. Dispatch Center Related General Plant Depreciation Reserve shall equal the product of General Plant Depreciation Reserve and the Dispatch Center Wages and Salaries Allocation Factor described above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, Dispatch Center Depreciation Reserve associated with the Post-2003 Dispatch Center Investment, shall equal the balance of the Dispatch Center Depreciation Reserve multiplied by the ratio of Post-2003 Dispatch Center Plant to total investment in Dispatch Center Plant.

e. Dispatch Center Related Accumulated Deferred Taxes shall equal the year-end balance of Total Accumulated Deferred Income Taxes, multiplied by the Dispatch Center Plant Allocation Factor described above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, Total Accumulated Deferred Income Taxes associated with the Post-2003 Dispatch Center Investment, shall equal the balance of total property-related accumulated deferred income taxes as recorded in FERC Accounts 281 and 282, multiplied by the Dispatch Center Plant Allocation Factor, further multiplied by the ratio of the Post-2003 Dispatch Center Plant to total investment in Dispatch Center Plant.

f. Other Regulatory Assets shall equal the year-end balance of FAS 106 multiplied by the Dispatch Center Wages and Salaries Allocation Factor described in Section (A) (2) (b) above and the year-end balance of FAS 109, net of FAS 109 liability, multiplied by the Dispatch Center Plant Allocation Factor described in above, plus the year-end unamortized balance of merger-related transmission costs recorded in FERC Account No. 182.3 as authorized by FERC multiplied by the Dispatch Center Transmission Plant Allocation Factor.

g. Dispatch Center Prepayments shall equal the year-end balance of Prepayments multiplied by the Dispatch Center Wages and Salaries Allocation Factor described above.

h. Dispatch Center Materials and Supplies shall equal the year-end balance of Transmission Plant Materials and Supplies multiplied times the Dispatch Center Plant Allocation Factor described above.

i. Dispatch Center Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Dispatch Center Transmission Related Operation and Maintenance Expense and Dispatch Center Transmission Related Administrative and General Expense.

2. The Cost of Capital Rate shall equal (a) the Weighted Cost of Capital, plus (b) Federal Income Taxes, plus (c) State Income Taxes.

a. the Weighted Cost of Capital will be calculated based upon the PTO's capital structure at the end of each year and will equal the sum of (i), (ii) and (iii) below.

The Cost of Capital Rate to be used in calculating the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, shall only reflect item (iii) below and shall apply in the manner indicated below.

i. the Long Term Debt Component, which equals the product of the actual weighted average embedded cost to maturity of Long Term Debt then outstanding and the ratio that Long-Term Debt is to Total Capital.

ii. the Preferred Stock Component, which equals the product of the actual weighted average embedded cost to maturity of Preferred Stock then outstanding and the ratio that Preferred Stock is to Total Capital.

iii. the Return on Equity Component, which equals the product of the PTO's Return on Equity as set in the PTO's RNS open access rate and the ratio that Common Equity is to Total Capital. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, the incremental return on equity shall be the product of 1.00% and the ratio of Common Equity to Total Capital.

b. Federal Income Taxes shall equal

$$\frac{A + [(C+B)/D]) \times FT}{1 - FT}$$

Where FT is the Federal Income Tax Rate and A is the sum of the Preferred Stock Component and the Return on Equity Component, as determined in Sections A.2.(a)(ii) and (iii) above, B is Dispatch Center Related Amortization of Investment Tax Credits, as determined in Section II.D. below, C is the Equity AFUDC component of Dispatch Center Depreciation Expense, as defined in Section B., and D is Dispatch Center Investment Base, as determined in A.1., above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, the incremental Federal Income Tax shall equal:

$$(A'*FT)/(1-FT)$$

Where FT is the Federal Income Tax Rate and A' is the incremental return on equity component, as determined in Section A.2.(a)(iii) above.

c. <u>State Income Taxes shall equal</u>

$$\frac{(A + [(C+B)/D] + \text{Federal Income Tax}) \times ST}{1 - ST}$$

Where ST is the State Income Tax Rate and A is the sum of the Preferred Stock Component and the Return on Equity Component, as determined in Section A.2.(a)(ii), and Section A.2.(a)(iii) above, and Federal Income Tax is the rate determined in Section A.2.(b) above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, the incremental State Income Tax shall equal:

$$(A' + \text{Federal Income Tax})*ST/(1-ST)$$

Where ST is the State Income Tax Rate and A' is the incremental return on equity component, as determined in Section A.2.(a)(iii) above, and Federal Income Tax is the rate determined in Section A.2.(b) above.

B. <u>Dispatch Center Depreciation Expense</u> shall equal the sum of Transmission Depreciation Expense for Dispatch Center Plant, plus an allocation of General Plant Depreciation Expense calculated by multiplying General Plant Depreciation Expense by the Dispatch Center Wages and Salaries Allocation Factor, described in Section (A)(1)(b) above.

C. Dispatch Center Related Amortization of Investment Tax Credits shall equal the PTO's Amortization of Investment Tax Credits multiplied by the Dispatch Center Plant Allocation Factor described above.

D. Dispatch Center Related Municipal Tax Expense shall equal the PTO's total Municipal Tax Expense multiplied by the Dispatch Center Plant Allocation Factor described above.

E. Dispatch Center Related Payroll Tax Expense shall equal the PTO's total electric payroll tax expense, multiplied by the Dispatch Center Wages and Salaries Allocation Factor, described above.

F. Dispatch Center Operation and Maintenance Expense shall equal all expenses related to SCADA operation charged to FERC Account Number 561 through 561.4, excluding any ISO and Local Control Center related expenses and any expenses recorded in this Account that were incurred under this OATT or the Local Service Schedules of this OATT as a Transmission Customer.

G. Dispatch Center Related Administrative and General Expenses shall equal the sum of (1) PTO's Administrative and General Expenses~~, excluding Accounts 924, 928 and 930.1,~~ multiplied by the Dispatch Center Wages and Salaries Allocation Factor, (2) Property Insurance multiplied by the Dispatch Center Plant Allocation Factor, and (3) Expenses included in Account 928 (excluding Merger-Related Costs included in Account 928) related to FERC Assessments multiplied by Dispatch Center Plant Allocation Factor, plus any other Federal and State Dispatch Center related expenses or assessments, plus specific Dispatch Center related expenses included in Account 930.1 plus Transmission Merger-Related Costs multiplied by the Dispatch Center Transmission Plant Allocation Factor.

APPENDIX B TO SCHEDULE 1 IMPLEMENTATION RULE CENTRAL MAINE POWER COMPANY LOCAL CONTROL CENTER

I. DEFINITIONS

Capitalized terms not otherwise defined in the Tariff and as used in this rule have the following definitions:

A. ALLOCATION FACTORS

1. Wages and Salaries Allocation Factor shall equal the ratio of the Local Control Center Direct Wages and Salaries to total direct wages and salaries excluding administrative and general wages and salaries.

2. Local Control Center Wages and Salaries Allocation Factor shall equal the ratio of the Transmission Local Control Center Direct Wages and Salaries to total Local Control Center Direct Wages and Salaries.

3. Local Control Center PTF Allocation Factor shall equal the ratio of the Local Control Center PTF Direct Wages and Salaries to the total Local Control Center Transmission Direct Wages and Salaries.

4. Local Control Center Plant Allocation Factor shall equal the ratio of the Total Investment in Local Control Center Plant to Total Plant in service.

B. TERMS

Administrative and General Expense shall equal the PTO's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928, and 930.1.

Amortization of Investment Tax Credits shall equal the PTO's credits as recorded in FERC Account No. 411.4

Amortization of Loss on Reacquired Debt shall equal the PTO's expenses as recorded in FERC Account No. 428.1

Other Regulatory Assets/Liabilities -FAS 106 shall equal the net of the PTO's FAS 106 balance as recorded in FERC Account 182.3 and any FAS 106 balance as recorded in the PTO's FERC Account No. 254.

Other Regulatory Assets/Liabilities -FAS 109 shall equal the net of the PTO's FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in the PTO's FERC Account No. 254.

Payroll Taxes shall equal those payroll expenses as recorded in the PTO's FERC Account Nos. 408.1 and 409.1.

Plant Held for Future Use shall equal the PTO's balance in FERC Account No. 105.

Prepayments shall equal the PTO's prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal the PTO's expenses as recorded in FERC Account No. 924.

PTF Local Control Center Direct Wages and Salaries shall equal the PTO's direct wages and salaries related to providing PTF Local Control Center services as recorded in FERC Account No. 561.

Local Control Center Direct Wages and Salaries shall equal the PTO's direct wages and salaries related to providing Local Control Center services as recorded in FERC Account Nos. 556, 561-561.4, and 581.

Local Control Center Operation and Maintenance Expense shall equal the PTO's expenses recorded in FERC Account Nos. 556, 561-561.4, & 581, less any costs included in FERC Account Nos. 561-561.4 that are otherwise recoverable pursuant to Subpart (1) of the Local PTF Transmission Related Scheduling and Dispatch Expense of the rule implementing the Schedule 1 rate surcharge of the OATT.

Local Control Center Plant Depreciation Reserve shall equal the PTO's depreciation reserve balance for Local Control Center Related Plant as recorded in FERC Account No. 108.

Materials and Supplies shall equal the PTO's balance as recorded in FERC Account No. 154.

Local Control Center Related Depreciation Expense shall equal the PTO's depreciation expense for Local Control Center Related Plant as recorded in FERC Account No. 403.

Local Control Center Related Plant shall equal the PTO's gross plant balances used for system control and dispatch purposes as recorded in FERC Account Nos. 303-399. To the extent that such plant includes any amounts recorded as transmission investment in FERC Account Nos. 350-359, such amounts will be excluded for purposes of determining annual transmission revenue requirements pursuant to the billing rule which implements Attachment F of the OATT.

Local Control Center Support Revenues shall equal the revenues received from Local Control Center supporters as recorded in FERC Account Nos. 454 and 456, excluding any revenues received under Schedule 1 of the OATT or the PTO's Local Service Schedule.

Total Accumulated Deferred Income Taxes shall equal the net of the deferred tax balances as recorded in FERC Account Nos. 281-283 and 190.

Total Loss on Reacquired Debt shall equal the PTO's balance as recorded in FERC Account No. 189.

Total Municipal Tax Expense shall equal the PTO's municipal tax expenses as recorded in FERC Account Nos. 408.1 and 409.1.

Total Plant in Service shall equal the PTO's total gross plant balance as recorded in FERC Account Nos. 301-399.

Transmission Local Control Center Direct Wages and Salaries shall equal the PTO's direct wages and salaries related to providing Local Control Center services as recorded in FERC Account No. 561-561.4.

II. CALCULATION OF TOTAL LOCAL CONTROL CENTER REVENUE REQUIREMENTS

The Local Control Center Revenue Requirements based on data for calendar year 2004 or later shall include an Incremental Return and Associated Income Taxes on Central Maine's local control center investments

included in the Regional System Plan and placed in service on or after January 1, 2004 (such investments referred to herein as “Post-2003 Investment”). The Incremental Return and Associated Income Taxes for Post-2003 Investment shall reflect a surcharge of a 100 basis point ROE adder applicable to certain investment base components as specified in the formula below. The data used in determining the Incremental Return and Associated Income Taxes for Post-2003 Investment shall be based on actual data in lieu of allocated data if specifically identified in Central Maine’s accounting records.

The Local Control Center Revenue Requirement shall equal the sum of the Local Control Center related (A) Return and Associated Income Taxes (including the Incremental Return and Associated Income Taxes for Post-2003 Investment), (B) Depreciation Expense, (C) Amortization of Loss on Reacquired Debt, (D) Amortization of Investment Tax Credits, (E) Municipal Tax Expense, (F) Payroll Tax Expense, (G) Operations and Maintenance Expense, (H) Administrative and General, minus (I) Support Revenues.

The Incremental Return and Associated Income Taxes for Post-2003 Investment shall be calculated using the investment base components specifically identified in Section A.1. of the formula below.

A. Return and Associated Income Taxes shall equal the product of the Local Control Center Investment Base and the Cost of Capital Rate reflected in the PTO’s Attachment F formula of the OATT. To calculate the Incremental Return and Associated Income Taxes for Post 2003 Investment, Local Control Center Investment Base shall only include Sections II.A.1.(a), (b), and (c), in the manner indicated.

1. Local Control Center Investment Base

The Local Control Center Investment Base will be the year end balances of Local Control Center related: (a) Plant, plus (b) Plant Held for Future Use, less (c) Depreciation Reserve, less (d) Accumulated Deferred Taxes, plus (e) Loss on Reacquired Debt, plus (f) Other Regulatory Assets/Liabilities, plus (g) prepayments, plus (h) Materials and Supplies, plus (i) Cash Working Capital.

(a) Local Control Center Related Plant shall equal the balance of the PTO’s Investment in Local Control Center Plant. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Investment, Post 2003 Local Control Center Plant shall be separately identified.

(b) Local Control Center Related Plant Held for Future Use shall equal the balance of Plant Held for Future Use multiplied by the Local Control Center Plant Allocation Factor.

(c) Local Control Center Related Depreciation Reserve shall equal the Depreciation Reserve for the PTO's investment in Local Control Center plant. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Investment, Local Control Center Depreciation Reserve shall equal the Depreciation Reserve for the PTO's Local Control Center Plant identified in (a) above.

(d) Local Control Center Related Accumulated Deferred Taxes shall equal the PTO's electric balance of Accumulated Deferred Income Taxes multiplied by the Local Control Center Plant Allocation Factor. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Investment, Local Control Center Accumulated Deferred Taxes shall equal the PTO's balance of total property related accumulated deferred income taxes recorded in FERC account 281and 282 multiplied by the Local Control Center Plant Allocation Factor and further multiplied by the ratio of Post-2003 Investment to Total Local Control Center Related Plant.

(e) Local Control Center Related Loss on Reacquired Debt shall equal the PTO's electric balance of Total Loss on Reacquired Debt multiplied by the Local Control Center Plant Allocation Factor.

(f) Local Control Center Related Other Regulatory Assets/Liabilities shall equal the PTO's electric balance of any deferred recovery of FAS 106 expenses multiplied by the Local Control Center Wages and Salaries Allocation Factor, plus the PTO's electric balance of FAS 109 multiplied by the Local Control Center Plant Allocation Factor.

(g) Local Control Center Related Prepayments shall equal the PTO's electric balance of prepayments multiplied by the Local Control Center Plant Allocation Factor.

(h) Local Control Center Related Materials and Supplies shall equal the PTO's electric balance of Plant Materials and Supplies, multiplied by the Local Control Center Plant Allocation Factor.

(i) Local Control Center Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Local Control Center Operation and Maintenance Expense, Local Control Center Related Administrative and General Expense.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) the PTO's Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon the capital structure at the end of each year and will equal the sum of (i),(ii), and (iii) below. The Cost of Capital Rate to be used in calculating the Incremental Return and Associated Income Taxes for Post-2003 Investment shall only reflect item (iii) below and shall apply in the manner indicated below

(b) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity of the PTO's long-term debt then outstanding and the ratio that long-term debt is to the PTO's total capital.

(c) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of the PTO's preferred stock then outstanding and the ratio that preferred stock is to the PTO's total capital.

(d) the return on equity component, which equals the product of the PTO's Return on Equity as set in the PTO's RNS open access rate and the ratio that common equity is to the PTO's total capital. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Investment, the incremental return on equity shall be the product of Central Maine's incremental return on equity of 1.0% and the ratio that common equity is to the PTO's total capital.

(e) Federal Income Tax shall equal

$$\frac{(A+[(C+B)/D]) \times FT}{1 - FT}$$

Where FT is the Federal Income Tax Rate and A is the sum of the preferred stock component and the return on equity component, as determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section II.D. below, C is the equity AFUDC component of Local Control Center Depreciation Expense, as defined in II.B., and D is Local Control Center Investment Base, as determined in II.A.1., above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Investment, the incremental Federal Income Tax shall equal

$$\frac{(A' * FT)}{(1 - FT)}$$

where FT is the Federal Income Tax Rate and A' is the incremental return on equity component, as determined in Section II.A.2.(a)(iii) above.

(f) State Income Tax shall equal

$$\frac{(A+[(C+B)/D] + \text{Federal Income Tax}) \times ST}{1 - ST}$$

Where ST is the State Income Tax Rate, A is the sum of the preferred stock component and return on equity component determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section II.D. below, C is the equity AFUDC component of Local Control Center Depreciation Expense, as defined in II.B., D is the Local Control Center Investment Base, as determined in II.A.1., above and Federal Income Tax is the rate determined in Section II.A.1.(b) above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Investment, the incremental State Income Tax shall equal

$$\frac{(A' + \text{Federal Income Tax})(ST)}{(1 - ST)}$$

where ST is the State Income Tax Rate, A' is the incremental return on equity component determined in Section II.A.2.(a)(iii) above, and Federal Income Tax is the rate determined in Section II.A.2.(b) above.

B. Local Control Center Depreciation Expense shall equal the Local Control Center Plant Depreciation Expense and Accumulated Amortization.

C. Local Control Center Related Amortization of Loss on Reacquired Debt shall equal the PTO's electric balance of Loss on Reacquired Debt multiplied by the Local Control Center Plant Allocation Factor.

D. Local Control Center Related Amortization of Investment Tax Credits shall equal the PTO's electric Amortization of Investment Tax Credits multiplied by the Local Control Center Plant Allocation Factor.

E. Local Control Center Related Municipal Tax Expense shall equal the PTO's total electric municipal tax expense multiplied by the Local Control Center Plant Allocation Factor.

F. Local Control Center Related Payroll Tax Expense shall equal the PTO's total electric payroll tax expense, multiplied by the Wages and Salaries Allocation Factor.

G. Local Control Center Operation and Maintenance Expense shall equal the PTO's Operation and Maintenance Expenses recorded in FERC Account Nos. 556, 561-561.4, and 581, less any costs included in FERC Account Nos. 561-561.4 that are otherwise recoverable pursuant to Subpart (1) of Local PTF Transmission Related Scheduling and Dispatch Expense of the rule implementing the Schedule 1 rate surcharge of the OATT.

H. Local Control Center Related Administrative and General Expenses shall equal the sum of (1) PTO's Administrative and General Expenses multiplied by the Wages and Salaries Allocation Factor, (2) Property Insurance multiplied by the Local Control Center Plant Allocation Factor, and (3) Expenses included in Account 928 related to FERC Assessments multiplied by the Local Control Center Plant Allocation Factor, plus any other Federal and State Local Control Center related expenses or assessments, plus specific Local Control Center related expenses included in Account 930.1.

I. Transmission Support Revenues shall equal the PTO's revenue received for providing system control and dispatch service.

III. CALCULATION OF LOCAL CONTROL CENTER TRANSMISSION REVENUE REQUIREMENTS

The Total Local Control Center Revenue Requirements derived in Section II. above are further multiplied by the Local Control Center Wages and Salaries Allocation Factor defined in Section I. A. 2. above to determine the transmission related revenue requirement, and further multiplied by the Local Control Center PTF Allocation Factor defined in Section I. A. 3. above, to determine the PTF Transmission related revenue requirements to be included in Schedule I of the OATT.

APPENDIX C TO SCHEDULE 1 IMPLEMENTATION RULE
CL&P DISPATCH CENTER REVENUE REQUIREMENT

This appendix calculates the CL&P Dispatch Center Revenue Requirement for use in calculating part (4) of the Local PTF Transmission-Related Scheduling and Dispatch expenses in the Schedule 1 Implementation Rule. The CL&P Dispatch Center Revenue Requirement for use during a calendar year shall be based on CL&P's costs for the immediately preceding calendar year.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section II.1 of the OATT and as used in this appendix have the following definitions:

Dispatch Center means CL&P's CONVEX dispatch center.

Dispatch Center Plant shall equal CL&P's year-end gross plant balances used for CL&P's Dispatch Center as recorded in FERC Account Nos. 303, 350-359, and 389-399.

Dispatch Center Depreciation Reserve shall equal CL&P's year-end depreciation reserve balance for Dispatch Center Plant as recorded in FERC Account No. 108. Dispatch Center Accumulated Deferred Income Taxes shall equal the net of CL&P's year-end deferred tax balances for Dispatch center Plant as recorded in FERC Account Nos. 281-283 and 190.

II. CALCULATION OF TOTAL DISPATCH CENTER REVENUE REQUIREMENT

The Dispatch Center Revenue Requirement shall equal the sum of (A) Dispatch Center Return and Associated Income Taxes, (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Amortization of Investment Tax Credits, and (D) Dispatch Center Municipal Tax Expense; provided, that during the period June 1, 2008 through May 31, 2009, the Dispatch Center Revenue Requirement shall equal the product of (i) the number of months (or fractions thereof) remaining in 2007 on and after the date upon which the Convex Agreements are permitted to be made effective by FERC, divided by 12 and (ii) the sum of (A) Dispatch Center Return and Associated Income Taxes, (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Amortization of Investment Tax Credits, and (D) Dispatch Center Municipal Tax Expense. "CONVEX Agreements" refers to the agreements between The Connecticut Light & Power Company and

various entities relating to the operation of the Dispatch Center and filed with FERC contemporaneously with the filing of this Appendix C.

A. Dispatch Center Return and Associated Income Taxes shall equal the product of the Dispatch Center Investment Base and the Cost of Capital Rate.

1. Dispatch Center Investment Base
The Dispatch Center Investment Base will be the year-end balances of:

(a) Dispatch Center Plant, less (b) Dispatch Center Depreciation Reserve, less (c) Dispatch Center Accumulated Deferred Income Taxes.

2. Cost of Capital Rate
The Cost of Capital Rate will equal (a) the Weighted Cost of Capital, plus (b) Federal Income Tax, plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon CL&P's capital structure at the end of each year and will equal the sum of (i), (ii), and (iii) below.

(i) The long-term debt component, which equals the product of the year-end balance of CL&P's first mortgage bonds and pollution control notes adjusted for premiums, discounts, debt expense and losses on reacquired debt and the ratio of the long term debt to CL&P's total capital.

(ii) The preferred stock component, which equals the product of the year-end balance of CL&P's preferred stock adjusted for premiums, discounts and unamortized issue expense and the ratio of the preferred stock to CL&P's total capital.

(iii) The common equity component, which equals the product of 10.3% and the ratio of the common equity to CL&P's total capital.

(b and c) Federal and State Income Taxes shall be computed as follows:

AxBxC

where: A = Dispatch Center Investment Base

B = Cost of equity capital (the sum of the preferred stock component and common equity component)

C = TC/(1-TE), where TE is the effective combined federal and state statutory income tax rates in effect at the applicable time.

B. Dispatch Center Depreciation Expense shall equal CL&P's Dispatch Center depreciation expense as recorded in FERC Account No. 403.

C. Dispatch Center Amortization of Investment Tax Credits shall equal CL&P's Dispatch Center amortization of investment tax credits as recorded in FERC Account No. 411.1.

D. Dispatch Center Municipal Tax Expense shall equal CL&P's Dispatch Center municipal tax expense as recorded in FERC Account Nos. 408.1 and 409.1.

SCHEDULE 21 - NSTAR

NSTAR ELECTRIC COMPANY

LOCAL SERVICE SCHEDULE

I COMMON SERVICE PROVISIONS

1.0 DEFINITIONS

Whenever used in this Local Service Schedule, in either the singular or plural number, the following capitalized terms shall have the meanings specified in this Section 1. Terms used in this Local Service Schedule that are not defined in this Local Service Schedule shall have the meanings set forth in the Tariff or customarily attributed to such terms by the electric utility industry in New England. Where there is a conflict between this Local Service Schedule and the Tariff, the terms here shall apply.

1.1 Annual Transmission Revenue Requirements

The total annual cost of the Transmission System shall be the amount specified in Attachment D until amended by NSTAR or modified by the Commission.

1.2 Annual True-Up

The reconciliation to actual costs of the estimated costs used for billing purposes under Section 4.0 of this Local Service Schedule for any Service Year.

1.3 Designated Agent

Any entity that performs actions or functions on behalf of NSTAR, an Eligible Customer, or the Transmission Customer required under the Local Service Schedule.

1.4 Firm Local Point-To-Point Service

Transmission service under this Local Service Schedule that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to this Local Service Schedule.

1.5 Load Ratio Share

Ratio of a Transmission Customer's most recently reported Monthly Network Load in the case of Network Customers and including, where applicable, the Reserved Capacity of Transmission Customers taking Firm Local Point-To-Point Service, to the total load of Network Customers and the Reserved Capacity of Transmission Customers taking Firm Local Point-To-Point Service.

1.6 Local Network

All transmission facilities constituting NSTAR's non-Pool Transmission Facilities (Non-PTF), excluding the Phase I/II HVDC-TF, which is defined in Schedule 20A of this OATT.

1.7 Local Network Load

The load that a Network Customer designates for Local Network Service under this Local Service Schedule. The Network Customer's Local Network Load shall include all load designated by the Network Customer, (including losses). A Network Customer may elect to designate less than its total load as Local Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete Points of Delivery as Local Network Load, the Eligible Customer is responsible for making separate arrangements under this Local Service Schedule for any Local Point-To-Point Service that may be necessary for such non-designated load.

1.8 Local Network Service

The transmission service provided under this Local Service Schedule over NSTAR's Local Network.

1.9 Local Network Upgrades

Modifications or additions to transmission-related facilities that are integrated with and support NSTAR's overall Transmission System for the general benefit of all users of such Transmission System.

1.10 Local Point-To-Point Service

The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under this Local Service Schedule over NSTAR's Local Network.

1.11 Long-Term Firm Local Point-To-Point Service

Firm Local Point-To-Point Service provided under this Local Service Schedule with a term of one year or more.

1.12 Monthly Network Load

A Network Customer's hourly load (including its designated Local Network Load not physically interconnected with NSTAR under Section 15.2 of this Local Service Schedule) coincident with NSTAR's Monthly Transmission System Peak.

1.13 Native Load Customers

The wholesale and retail power customers of NSTAR on whose behalf NSTAR, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate NSTAR's system to meet the reliable electric needs of such customers.

1.14 NERC

North American Electric Reliability Council, the Electric Reliability Organization of the United States.

1.15 Non-Firm Local Point-To-Point Service

Local Point-To-Point Service under this Local Service Schedule that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in this Local Service Schedule. Non-Firm Local Point-To-Point Service is available on a stand-alone basis for periods ranging from one hour to one month.

1.16 NPCC

Northeast Power Coordinating Council, a regional reliability council of NERC.

1.17 NSTAR

NSTAR Electric Company, a Massachusetts Corporation with offices located at 800 Boylston Street, Boston, Massachusetts 02199. NSTAR owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce and provides service pursuant to the rates, terms and conditions of this Local Service Schedule and the applicable terms and conditions of this Local Service Schedule.

1.18 NSTAR's Monthly Transmission System Load

NSTAR's Monthly Transmission System Peak minus the coincident peak usage of all Firm Local Point-To-Point Service customers pursuant to Part II of this Local Service Schedule plus the Reserved Capacity of all Firm Local Point-To-Point Service customers.

1.19 NSTAR's Monthly Transmission System Peak

The maximum firm usage of NSTAR's Transmission System in a calendar month.

1.20 Parties

NSTAR and the Transmission Customer receiving service under this Local Service Schedule.

1.21 Point(s) of Delivery

Point(s) on NSTAR's Transmission System where capacity and energy transmitted by NSTAR will be made available to the Receiving Party under this Local Service Schedule. The Point(s) of Delivery shall be specified in the Transmission Service Agreement.

1.22 Point(s) of Receipt

Point(s) of interconnection on NSTAR's Transmission System where capacity and energy will be made available to NSTAR by the Delivering Party under this Local Service Schedule. The Point(s) of Receipt shall be specified in the Transmission Service Agreement.

1.23 Service Year

The calendar year in which the Transmission Customer is receiving service under this Local Service Schedule.

1.24 Short-Term Firm Local Point-To-Point Service

Firm Local Point-To-Point Service under this Local Service Schedule with a term of less than one year.

1.25 Transmission System

The facilities owned, controlled or operated by NSTAR that are used to provide transmission service under this Local Service Schedule.

2.0 ANCILLARY SERVICES

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. NSTAR is required to provide and the Transmission Customer is required to purchase the following Ancillary Services (i) Scheduling, System Control and Dispatch, and (ii) Supplemental End-Use Reactive Support Service.

In addition, the Transmission Customer is required to purchase additional Ancillary Services under the terms and conditions of the Tariff. The Transmission Customer may not decline the Transmission Provider's offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it

will purchase from the Transmission Provider. A Transmission Customer that exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or an Eligible Customer that uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved is required to pay for all of the Ancillary Services identified in this section that were provided by the Transmission Provider associated with the unreserved service. The Transmission Customer or Eligible Customer will pay for Ancillary Services based on the amount of transmission service it used but did not reserve. NSTAR shall also assess a penalty for any unauthorized use of Ancillary Services by the Transmission Customer, based on the amount of transmission service it used but did not reserve, using the rate shown for such Ancillary Service.

The prices and/or compensation methods for Local System Control and Dispatch Services and Supplemental End-Use Reactive Support Service are described in Attachment D and Schedule 2, respectively, attached to and made a part of this Local Service Schedule. Three principal requirements apply to discounts for Ancillary Services provided by NSTAR in conjunction with its provision of transmission service as follows: (1) any offer of a discount made by NSTAR must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. A discount agreed upon for an Ancillary Service must be offered for the same period to all Eligible Customers on NSTAR's system.

3.0 CREDITWORTHINESS

NSTAR's creditworthiness procedures are specified in Attachment L to this Local Service Schedule.

4.0 BILLING AND PAYMENT

4.1 Billing Procedure

Within a reasonable time after the first day of each month, NSTAR shall submit an invoice to the Transmission Customer for the charges for all services furnished under this Local Service Schedule during the preceding month. The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to NSTAR, or by wire transfer to a bank named by NSTAR.

Billings hereunder shall be based on cost estimates made by NSTAR subject to Annual True-up

when actual costs for the Service Year are known. Such Annual True-up shall occur no later than six (6) months after the close of the Service Year to which the Annual True-up relates. To the extent bill adjustments are required pursuant to the Annual True-up, such adjustments shall bear interest calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii).

(i) The Annual True-Up shall be performed by recalculation of the costs for the Service Year based on actual cost and load information as reported in the FERC Form 1 for that Service Year and shall develop thereby an Embedded Cost Charge, defined in Section 16.1, to be used in the said Annual True-Up. The Annual True-Up shall also include the CWIP Supplement referred to in clause (ix).

(ii) The Annual True-Up will be filed with FERC by NSTAR in an informational filing on or before May 31 of the year following the Service Year and posted on NSTAR's website. The Annual True-Up so filed and posted shall include the actual report showing the basis for the computation of the Postretirement Benefits Other Than Pensions ("PBOP") component of "Administrative and General Expense" and shall also show the basis for the allocation of the PBOP expense to the service provided under this Local Service Schedule; provided that the information so filed and posted shall not include confidential information. The informational filing shall include a Benefits Labor Loader showing the basis for such allocation of both PBOP and prepaid pension costs. On request, NSTAR shall provide any Network Customer the Annual True-Up by May 31 of the year following the Service Year. Any difference between the estimated Embedded Cost Charge and the actual Embedded Cost Charge shall be collected from or refunded to the Network Customer in the month of June of the calendar year following the Service Year.

(iii) The Annual True-Up provided pursuant to Section 4.1(ii) shall include an attestation by a Company officer that "to the best of the affiant's knowledge, information and belief the data employed in the Annual True-Up reflect NSTAR's per book costs for the Service Year, conform to NSTAR's FERC Form 1 Report for the Service Year, conform in all material respects to the FERC Uniform System of Accounts, and have been developed in accordance with the provisions of this rate schedule."

(iv) The Annual True-Up shall also be accompanied by supplementary information which

shall (i) detail any data used in the Annual True-Up not directly taken from NSTAR's FERC Form 1 Report and (ii) identify any FERC Form 1 Account used to record expenses during the Service Year that was not used in the preceding Service Year. The supplementary information shall be certified by an officer of NSTAR.

(v) There shall be an "Audit Period" that will extend from July 1 through September 30 of the year following the Service Year; provided that NSTAR and the Network Customer may agree to extend the Audit Period beyond September 30 by their mutual written agreement. During the Audit Period, any Network Customer shall have the right to conduct an audit or other inspection of the actual data used in the Annual True-Up and/or request additional information not included with the Annual True-Up. NSTAR shall not withhold information, including PBOP information, on grounds of confidentiality, but is entitled to make such information available pursuant to a confidentiality agreement and to restrict access to non-competitive duty personnel and to other personnel whose receipt of the information would not be in violation of the Standards and/or Code of Conduct as prescribed by FERC. During the Audit Period, NSTAR shall exercise all commercially reasonable efforts to provide the Network Customer, within 10 business days, such additional information as the Network Customer may request in order to understand the Annual True-Up. To the extent requested, NSTAR shall meet with any Network Customer to provide such additional information, explanation, and/or clarification regarding the Annual True-Up as the Network Customer may request.

(vi) During the Audit Period, the Network Customer shall have the right to request NSTAR to adjust the Annual True-Up, and any refunds it received or payments it made, pursuant to the Annual True-Up to the extent of any discrepancy between the data employed by NSTAR in performing the Annual True-Up and the actual data for the Service Year or in the event NSTAR developed the Annual True-Up in a manner that is inconsistent with this rate schedule.

(vii) If NSTAR does not agree to the Network Customer's request, as set forth in subparagraph (vi), and if NSTAR and the Network Customer are in disagreement as to any component of the Annual True-Up, the Network Customer within thirty days following the conclusion of the Audit Period may request and NSTAR shall agree to non-binding dispute resolution either conducted with the FERC Staff or otherwise at the Network Customer's choice. The Network Customer may file a complaint with the Commission within thirty days following completion of the audit period or the dispute resolution process and shall specify in that

complaint the component or components of the Annual True Up that the Network Customer disputes. In the event such a complaint is filed, the disputed component or components of the Annual True Up shall be subject to refund as of the first day of the Service Year pending the results of the Commission investigation instituted as a result of such complaint. If the Network Customer fails to object to the Annual True-Up within thirty days following conclusion of the Audit Period, NSTAR's costs for the Service Year shall be deemed final, and its revenues from the Network Customer for the Service Year shall not be subject to refund; provided that the deadline for such an objection shall (i) be extended for ninety days following the date NSTAR makes any subsequent change to its Form 1 data for the Service Year that affects the Annual True-Up and (ii) shall not apply if the Commission prior to December 31st of the calendar year following the Service Year institutes its own investigation of NSTAR's Service Year costs.

(viii) Subject to the limitation that the Massachusetts Attorney General does not make or receive transmission payments or refunds, the Massachusetts Attorney General shall have the same procedural rights under this Section 4.0 as a Network Customer. This in no way obligates the Massachusetts Attorney General to the dispute resolution or arbitration procedures outlined in Sections 5.1 and 5.2.

(ix) The Annual True-Up shall include a CWIP Supplement, which shall apply to the Service Year, shall be filed with FERC by NSTAR in an informational filing on or before June 30 of the year following the Service Year and posted on NSTAR's website to the extent it does not include critical energy infrastructure information or other confidential information. The CWIP Supplement shall include NSTAR Electric's most recent annual construction forecast. The CWIP Supplement shall provide for each project included in rate base during the Service Year the actual amounts of CWIP recorded for each project, the related accounts, such as AFUDC and regulatory liability, inclusive of all subaccounts, and the resulting effect on the CWIP revenue requirement in line item detail. The CWIP Supplement shall also identify any changes in NSTAR's accounting practices related to the accrual of AFUDC and the inclusion of CWIP in rate base or related to ensuring that AFUDC is not accrued on CWIP balances that have been included in rate base.

For each "new project" (a project that is estimated to enter rate base for the first time in the Service Year), the CWIP Supplement shall provide, to the extent not included in the construction forecast, a detailed statement of the reasons for undertaking the project, the benefits to be derived

from the project, and the alternatives to or consequences of not undertaking the project. For each "pre-existing project" (a project that entered rate base prior to the Service Year), the CWIP Supplement shall include an update on the status of the project including any material change regarding the estimated cost of the project, the estimated in-service date and/or project timelines, and whether there is any change in the need for the project or in alternatives to the project. CWIP associated with a project cannot be included in the rate base for a Service Year unless it is included in the CWIP Supplement applicable to the Service Year.

The CWIP Supplement applicable to a Service Year shall include a CWIP Work Order/Project Reference Aid ("Reference Aid") that distinguishes between new projects and pre-existing projects and that provides for each project, whether new or pre-existing, ISO information, to the extent such information is available and applies to a project, and NSTAR information. The ISO information shall include a short description of the project, the year the project was approved through the ISO process, and the project identification number for ISO purposes. The NSTAR information shall include reference to the most recent NSTAR construction planning forecast in which the project appeared, the page of the plan at which the project description begins, the NSTAR numeric project designation, the NSTAR description of the project, the work order or work orders associated with the project, and a description of each work order. The Reference Aid shall present this information in a format so that the ISO information related to a project can be correlated with the NSTAR information related to a project. The Reference Aid, as described above, is based on current ISO and NSTAR tracking systems for projects under or proposed for construction and is to be modified to present equivalent information if and to the extent the ISO and/or NSTAR tracking system is modified.

The 50% of transmission-related CWIP included in rate base is subject to the Annual True-Up and dispute resolution provisions of this Section 4.1 regarding differences between actual and estimated costs. In addition, the CWIP included in rate base for a project shall be subject to refund as provided below to the extent the Commission makes a finding that the inclusion of such CWIP in rate base is unjust and unreasonable. In the case of a new project, the refund amount shall be the CWIP actually recovered from customers from the date of collection to the date of refund. In any proceeding regarding a new project, NSTAR shall bear the burden of proving that inclusion of CWIP related to the new project in rate base is just and reasonable. In the case of a pre-existing project, the refund amount shall be for the CWIP actually recovered from customers from the prospective refund effective date specified by the Commission pursuant to the

provisions of Section 206 of the Federal Power Act to the date of refund. All refunds shall include interest at the rate specified in 18 C.F.R. § 35.19a(a)(2)(iii). Any customer and/or the Massachusetts Attorney General can request that the Commission institute an investigation into the justness and reasonableness of including CWIP for any project in rate base and the Commission may institute such an investigation sua sponte.

Nothing in this Clause (ix) authorizes the inclusion in rate base of more than 50% of the CWIP balance attributable to a project. Absent a Commission finding of imprudence, NSTAR shall be entitled to accrue AFUDC as to any CWIP that is excluded from rate base. The Commission's institution of an investigation as to the justness and reasonableness of including CWIP associated with a project in rate base does not affect the timing or the finality of other components of the Annual True-Up as established by clause (vii) hereof.

With the exception of curtailment penalty charges pursuant to Section 16.2 and Schedule 3, paragraph 5 and Schedule 4, paragraph 6, any Annual True-Up rendered under this Local Service Schedule and any other monthly bill to which the Annual True-Up relates shall be binding on both Parties one (1) year from the date of NSTAR's Annual True-Up, unless previously disputed pursuant to this section or Section 4.3 of this Local Service Schedule.

4.2 Interest on Unpaid Balances

Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by NSTAR.

4.3 Customer Default

In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to NSTAR on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after NSTAR notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, NSTAR may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request.

In the event of a billing dispute between NSTAR and the Transmission Customer, NSTAR will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then NSTAR may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

5.0 DISPUTE RESOLUTION PROCEDURES

5.1 Internal Dispute Resolution Procedures

Any dispute between a Transmission Customer and NSTAR involving transmission service under this Local Service Schedule (excluding applications for rate changes or other changes to this Local Service Schedule, or to any Service Agreement entered into under this Local Service Schedule, which shall be presented directly to the Commission for resolution) shall be referred to a designated senior representative of NSTAR and a senior representative of the Transmission Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days [or such other period as the Parties may agree upon] by mutual agreement, such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below.

5.2 External Arbitration Procedures

Any arbitration initiated under this Local Service Schedule shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) days of the referral of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association and any applicable Commission regulations or ISO rules.

5.3 Arbitration Decisions

Unless otherwise agreed, the arbitrator(s) shall render a decision within ninety (90) days of appointment and shall notify the Parties in writing of such decision and the reasons therefore. The arbitrator(s) shall be authorized only to interpret and apply the provisions of this Local Service Schedule and any Service Agreement entered into under this Local Service Schedule and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act and/or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with the Commission if it affects jurisdictional rates, terms and conditions of service or facilities.

5.4 Costs

Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable:

(a) the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or

(b) one half the cost of the single arbitrator jointly chosen by the Parties.

5.5 Rights Under The Federal Power Act

Nothing in this section shall restrict the rights of any party to file a complaint with the Commission under relevant provisions of the Federal Power Act.

II LOCAL POINT-TO-POINT SERVICE

6.0 NATURE OF FIRM LOCAL POINT-TO-POINT SERVICE

6.1 Curtailment of Firm Local Point-To-Point Service

In the event a Transmission Customer (including Third-Party Sales by NSTAR) fails to curtail a transaction when requested to do so by NSTAR, the Local Control Center and/or ISO, as

appropriate and pursuant to this Section, NSTAR shall assess a penalty charge to the Transmission Customer. Said penalty charge will be determined in accordance with this Local Service Schedule.

In the event NSTAR, the Local Control Center or ISO exercises their rights to effect a Curtailment, in whole or in part, of Firm Local Point-To-Point Service, no credit or other adjustment shall be provided as a result of the Curtailment with respect to the charge payable by the Transmission Customer.

6.2 Classification of Firm Local Point-To-Point Service

(a) The Transmission Customer taking Firm Local Point-To-Point Service may, (1) change its Points of Receipt and Delivery to obtain service on a non-firm basis consistent with the terms of Part I, Section 10(a) of Schedule 21 of the OATT or (2) request a modification of the Points of Receipt or Delivery on a firm basis pursuant to the terms of Part I, Section 10(b) of Schedule 21 of the OATT; provided that NSTAR continues to be compensated for any costs associated with the construction or upgrading of facilities associated with the original firm service.

(b) In the event that a Transmission Customer’s use of the Transmission System (including Third-Party Sales by NSTAR) exceeds that Transmission Customer’s Reserved Capacity at any Point of Receipt or Point of Delivery in any hour, NSTAR will charge the Transmission Customer a penalty charge in accordance with Section 10 and Schedule 3 of this Local Service Schedule.

(c) Under no circumstance will NSTAR be obligated to provide Control Area Ancillary Services to the Transmission Customer in support of any excess capacity (i.e., capacity in excess of Transmission Customer’s Reserved Capacity).

7.0 NATURE OF NON-FIRM LOCAL POINT-TO-POINT SERVICE

7.1 Classification of Non-Firm Local Point-To-Point Service

In the event that a Transmission Customer’s use of the Transmission System (including Third-Party Sales by NSTAR) exceeds that Transmission Customer’s non-firm Reserved Capacity at any Point of Receipt or Point of Delivery, NSTAR will charge the Transmission

Customer a penalty charge in accordance with Section 10 and Schedule 4 of this Local Service Schedule for such excess. Under no circumstance will NSTAR be obligated to provide Control Area Ancillary Services to the Transmission Customer in support of any excess capacity (i.e., capacity in excess of Transmission Customer's Reserved Capacity).

7.2 Curtailment or Interruption of Service

In the event a Transmission Customer (including Third-Party Sales by NSTAR) fails to implement a Curtailment or Interruption when requested to do so by NSTAR, the Local Control Center and/or ISO, as appropriate and pursuant to this Section, NSTAR shall assess a penalty charge. Said penalty charge will be determined in accordance with Section 10 and Schedule 4 of this Local Service Schedule.

In the event NSTAR, the Local Control Center and/or ISO exercises its rights to effect a Curtailment, in whole or part, of Non-Firm Local Point-To-Point Service, no credit or other adjustment shall be provided as a result of the Curtailment with respect to the charge payable by the Transmission Customer.

In the event NSTAR, the Local Control Center and/or ISO exercises its rights to effect an Interruption, in whole or part, of Non-Firm Local Point-To-Point Service, the charge payable by the Transmission Customer shall be computed as if the term of service actually rendered were the term of service reserved; provided that an adjustment of the charge shall be made only when the Interruption is initiated by NSTAR, the Local Control Center and/or ISO, not when the customer fails to deliver energy to NSTAR.

8.0 SERVICE AVAILABILITY

8.1 Real Power Losses

Real power losses associated with transactions on NSTAR's Local Network shall be determined based on estimated average system losses for metering points on NSTAR's Local Network; the loss factor will be three and one tenth percent (3.1%).

8.2 Load Shedding

To the extent that a system contingency exists on the NSTAR Transmission System or the New England Transmission System and NSTAR, the Local Control Center or ISO, as appropriate,

determines that it is necessary to shed load, the Parties shall shed load in accordance with the procedures specified by NSTAR, the Local Control Center and/or ISO.

9.0 METERING

Unless otherwise agreed, the Transmission Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted under the Local Service Schedule and to communicate the information to NSTAR. However, NSTAR reserves the right to determine and approve any and all metering equipment and the metering installation design, such approval not to be unreasonably withheld.

All meters, including any recording devices or telemetry equipment must be operated and maintained in accordance with ISO Operating Procedures. Unless otherwise agreed, such equipment shall remain the property of NSTAR.

If at any time any metering equipment owned by NSTAR (or the Transmission Customer, if so agreed) is found to be inaccurate in excess of two percent (2%), up or down, the owner of the metering equipment shall cause it to be made accurate or replaced and the meter readings and rate computation for the period of inaccuracy shall be adjusted to correct such inaccuracy so far as the same can be reasonably ascertained, but no adjustment prior to the beginning of the next preceding month shall be made except by agreement of the Parties. In addition to an annual routine test, the owner of the metering equipment shall cause such equipment to be tested at any time upon written request of the other Party. If such equipment proves accurate within two percent (2%), up or down, the expense of the test shall be borne by the Party requesting the test. The determination of percent accuracy shall be in accordance with the weighted average percent registration as described in ANSI C12.1-1988, Section 6.1.8.1. The owner of the metering equipment shall comply with any reasonable request of the other Party concerning the sealing of meters, the presence of a representative when the seals are broken and tests are made, and other matters affecting the accuracy of the measurement of electricity hereunder.

10.0 COMPENSATION FOR LOCAL POINT-TO-POINT SERVICE

Rates for Firm and Non-Firm Local Point-To-Point Service shall be determined as set forth in the Schedules appended to this Local Service Schedule: Firm Local Point-To-Point Service (Schedule 3) and Non-Firm Local Point-To-Point Service (Schedule 4). Such rates shall be determined on the basis of estimated costs for each Service Year until the actual costs for such Service Year are determined.

Thereafter, payments made on such estimated costs shall be recalculated based on actual data for that Service Year, and an appropriate billing adjustment shall be made pursuant to Section 4 of this Local Service Schedule.

NSTAR shall use this Local Service Schedule to make its Third-Party Sales to be transmitted as Local Point-To-Point Service. NSTAR shall account for such use at the applicable rates, pursuant to Section II.8.5 of the Tariff.

11.0 STRANDED COST RECOVERY

NSTAR may seek to recover stranded costs from the Transmission Customer pursuant to this Local Service Schedule in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, NSTAR must separately file any specific proposed stranded cost charge under Section 205 of the Federal Power Act.

III LOCAL NETWORK SERVICE

12.0 NATURE OF LOCAL NETWORK SERVICE

12.1 Real Power Losses

Real power losses associated with transactions on Non-PTF shall be determined based on estimated average system losses for metering points on NSTAR's Local Network; the loss factor will be three and one tenth percent (3.1%).

12.2 Metering

Unless agreed otherwise, all meters, including any recording devices or telemetry equipment shall be owned, operated, maintained and tested by NSTAR or its Designated Agent in accordance with ISO Operating Procedures at the Transmission Customer's expense. NSTAR shall provide access to metering data, including telephone line access, which may reasonably be required to facilitate measurement and billing under a Service Agreement at the requesting Party's expense.

NSTAR reserves the sole right to determine appropriate metering installations. When new metering equipment is required, it shall be supplied by NSTAR, at the Transmission Customer's expense, including applicable taxes, and overhead costs, in conformity with ISO Operating

Procedures.

If at any time any metering equipment owned by NSTAR (or Transmission Customer, if so agreed) is found to be inaccurate in excess of two percent (2%), up or down, the owner of the metering equipment shall cause it to be made accurate or replaced and the meter readings and rate computation for the period of inaccuracy shall be adjusted to correct such inaccuracy so far as the same can be reasonably ascertained, but no adjustment prior to the beginning of the next preceding month shall be made except by agreement of the Parties. In addition to an annual routine test, the owner of the metering equipment shall cause such equipment to be tested at any time upon written request of the other Party.

If such equipment proves accurate within two percent (2%), up or down, the expense of the test shall be borne by the Party requesting the test. The determination of percent accuracy shall be in accordance with the weighted average percent registration as described in ANSI C12.1-1988, Section 6.1.8.1. The owner of the metering equipment shall comply with any reasonable request of the other Party concerning the sealing of meters, the presence of a representative when the seals are broken and tests are made, and other matters affecting the accuracy of the measurement of electricity hereunder.

13.0 NETWORK RESOURCES

13.1 Operation of Network Resources

The Network Customer shall not operate its designated Network Resources located in the Network Customer's or NSTAR's Control Area such that the output of those facilities exceeds its designated Local Network Load, plus Non-Firm Sales delivered pursuant to Part II of this Local Service Schedule, plus losses. This limitation shall not apply to changes in the operation of a Transmission Customer's Network Resources at the request of NSTAR to respond to an emergency or other unforeseen condition which may impair or degrade the reliability of the Transmission System.

13.2 Transmission Arrangements for Network Resources Not Physically Interconnected With NSTAR

The Network Customer shall be responsible for any arrangements necessary to deliver capacity and energy from a Network Resource not physically interconnected with NSTAR's Transmission

System. NSTAR will undertake reasonable efforts to assist the Network Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice.

13.3 Use of Interface Capacity by the Network Customer

Unless otherwise provided under the Tariff, there is no limitation upon a Network Customer's use of NSTAR's Transmission System at any particular interface to integrate the Network Customer's Network Resources (or substitute economy purchases) with its Local Network Loads. However, unless otherwise provided by the Tariff, a Network Customer's use of NSTAR's total interface capacity with other transmission systems may not exceed the Network Customer's Load.

13.4 Network Customer Owned Transmission Facilities

The Network Customer that owns existing transmission facilities that are integrated with NSTAR's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration the Network Customer must demonstrate that its transmission facilities are integrated into the plans or operations of NSTAR to serve its power and transmission customers. For facilities constructed by the Network Customer subsequent to the Service Commencement Date under this Local Service Schedule, the Network Customer shall receive credit where such facilities are jointly planned and installed in coordination with NSTAR. Calculation of the credit shall be addressed in either the Network Customer's Service Agreement or any other agreement between the Parties.

14.0 DESIGNATION OF LOCAL NETWORK LOAD

14.1 Local Network Load

The Network Customer must designate the individual Local Network Loads on whose behalf NSTAR will provide Local Network Service. The Local Network Loads shall be specified in the Service Agreement.

14.2 Local Network Load Not Physically Interconnected with NSTAR

This section applies to both initial designation pursuant to Section 15.1 and the subsequent addition of new Local Network Load not physically interconnected with NSTAR. To the extent that the Network Customer desires to obtain transmission service for a load outside NSTAR's Transmission System, the Network Customer shall have the option of (1) electing to include the

entire load as Local Network Load for all purposes under this Local Service Schedule and designating Network Resources in connection with such additional Local Network Load, or (2) excluding that entire load from its Local Network Load and purchasing Local Point-To-Point Service under this Local Service Schedule.

To the extent that the Network Customer gives notice of its intent to add a new Local Network Load as part of its Local Network Load pursuant to this section, the request must be made through a modification of service pursuant to a new Application.

15.0 LOAD SHEDDING AND CURTAILMENTS

15.1 Procedures

Prior to the Service Commencement Date, NSTAR and the Network Customer shall establish Load Shedding and Curtailment procedures pursuant to the OATT with the objective of responding to contingencies on the Transmission System. The Parties will implement such programs during any period when NSTAR, the Local Control Center or ISO, as appropriate, determines that a system contingency exists and such procedures are necessary to alleviate such contingency. NSTAR will notify all affected Network Customers in a timely manner of any scheduled Curtailment.

15.2 Allocation of Curtailments

NSTAR shall, on a non-discriminatory basis, effect a Curtailment of the transaction(s) that effectively relieves the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by NSTAR and Network Customer in proportion to their respective Load Ratio Shares. NSTAR shall not direct the Network Customer to effect a Curtailment of schedules to an extent greater than NSTAR would effect a Curtailment of NSTAR’s schedules under similar circumstances.

15.3 Load Shedding

To the extent that a system contingency exists on NSTAR’s Transmission System and ISO, the Local Control Center or NSTAR, as appropriate, determines that it is necessary for NSTAR, Local Point-to-Point Customers and Network Customers to shed load, the Parties shall shed load in accordance with the OATT.

15.4 System Reliability

Any Curtailment of Local Network Service will be not unduly discriminatory relative to NSTAR's use of the Transmission System on behalf of its Native Load Customers. In the event that the Network Customer fails to respond to established Load Shedding and Curtailment procedures, NSTAR shall assess a penalty charge. Said penalty charge will be determined in accordance with Section 16.2.

16.0 RATES AND CHARGES

Rates for Local Network Service shall be determined as set forth in this Section 16 on the basis of estimated costs for each Service Year until the actual costs for such Service Year are determined. Thereafter, payments made on such estimated costs shall be recalculated based on actual data for that Service Year, and all appropriate billing adjustments shall be made pursuant to Section 4 of this Local Service Schedule.

The Network Customer shall pay NSTAR for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following:

16.1 Monthly Demand Charge

The Network Customer shall pay a Monthly Demand Charge which shall be the Embedded Cost Charge. The Embedded Cost Charge shall be determined by multiplying the Network Customer's Load Ratio Share by one twelfth (1/12) of NSTAR's Annual Transmission Revenue Requirements, as determined in accordance with Attachment D of this Local Service Schedule and as subject to an Annual True-up pursuant to Section 4. The Embedded Cost Charge is based on NSTAR's system average embedded cost. In the event NSTAR seeks to apply a rate based on a methodology other than average embedded cost to all or any part of a Network Customer's service, either already being provided or proposed to be provided, NSTAR shall provide the affected Network Customer thirty days advance written notice of any filing with the Commission seeking to implement such a rate and shall comply with all applicable requirements of the Commission and the Tariff. Any dispute as to NSTAR's position concerning proposed cost allocation shall be addressed as provided in Section II.7(g) of Schedule 21-Local Service to Section II of the Tariff; provided that nothing in this provision prevents NSTAR from filing with the Commission at any time to establish new rates pursuant to the provisions of Section 205 of the FPA or a Network Customer from opposing such a filing, and nothing in this provision is intended to reflect a Network Customer's agreement that NSTAR has the rights set out in this

Section 16.1 or is intended to prevent the affected Network Customer from filing a complaint with the Commission at any time pursuant to the provisions of Section 206 of the FPA or NSTAR from opposing such a filing.

16.2 Curtailment Penalty Charge

If the Transmission Customer fails to respond to established emergency load shedding and curtailment procedures to relieve emergencies on the transmission system, NSTAR may assess a penalty charge to the Transmission Customer. Said penalty charge will be equal to two (2) times the Monthly Demand Charge for Local Network Service, as calculated in accordance with Section 16.1 of this Local Service Schedule, for the month in which such service was not curtailed or interrupted.

16.3 [Reserved]

16.4 Taxes and Fees Charge

16.4.1 If NSTAR incurs tax liability currently for which it will in subsequent years receive tax benefits (for example, a taxable contribution in aid of construction) then Transmission Customer shall pay to NSTAR an amount sufficient to reimburse NSTAR, on a net present value basis, for the reasonably projected costs resulting from the tax liability incurred in the current year less the reasonably projected tax benefits received by NSTAR in future years. Sections 16.4.1 and 16.4.2 are intended to apply to those Transmission Customers for whom Direct Assignment Facilities are constructed pursuant to this Local Service Schedule and to any Transmission Customer's appropriate share of the cost of any required Local Network Upgrades to the extent that any such Local Network Upgrade is identified pursuant to the study procedures outlined in Schedule 21-Local Service, Section II.7(d) and permitted or required by Commission ruling to be paid as a contribution in aid of construction.

16.4.2 If NSTAR takes a position that any particular transaction under any section of the Local Service Schedule does not constitute a transaction of the type described immediately above, and that position is subsequently reversed by Treasury ruling or regulation or court action, then the Transmission Customer shall pay to NSTAR an amount calculated as described above, but additionally taking into account any interest assessment required

to be paid by NSTAR.

16.4.3 At its effective date, this Section 16.4 applies only to contributions in aid of construction ("CIAC"). NSTAR reserves the right to file under Section 205 of the FPA to modify this provision to apply to items other than CIAC and the Network Customer reserves the right to oppose any such filing.

17.0 OPERATING ARRANGEMENTS

17.1 Operating Requirements

The terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of this Local Service Schedule shall be specified in the OATT. The OATT shall provide for the Parties to:

(i) operate and maintain equipment necessary for integrating the Network Customer within NSTAR's Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment),

(ii) transfer data between NSTAR and the Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside NSTAR's Transmission System, interchange schedules, unit outputs for redispatch required under Section 15, voltage schedules, loss factors and other real time data),

(iii) use software programs required for data links and constraint dispatching,

(iv) exchange data on forecasted loads and resources necessary for long-term planning, and

(v) address any other technical and operational considerations required for implementation of this Local Service Schedule, including scheduling protocols.

The OATT will recognize that the Network Customer shall either:

(i) operate as a Control Area under applicable guidelines of the Electric Reliability Organization (ERO), as defined in 18 CFR 38.1, and ISO,

(ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with NSTAR, or

(iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies the applicable reliability guidelines of the ERO and ISO. NSTAR shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services.

17.2 Network Operating Committee

A Network Operating Committee (Committee) shall be established to coordinate operating criteria for the Parties' respective responsibilities under the OATT. Each Network Customer shall be entitled to have at least one representative on the Committee. The Committee shall meet from time to time as need requires, but no less than once each calendar year.

SCHEDULE 2

SUPPLEMENTAL END-USE REACTIVE SUPPORT SERVICE

In the event that power factor levels and reactive supply requirements set forth in the service agreement or other associated operating or interconnect agreement are not maintained by the Delivering Party (or, as appropriate, the Receiving Party), in accordance with applicable ISO standards and practices then NSTAR shall charge the Transmission Customer to take corrective action. The Transmission customer shall compensate NSTAR for installing the necessary equipment, whether in the form of generating units or other non-generating resources, such as demand resources, to correct the incremental difference between the Transmission Customer's lowest (or highest) power factor level and that which is an acceptable level in accordance with ISO standards and practices. The charges will be based upon the necessary level of reactive power supply required to correct the deficiency in the power factor level.

For the KVAR demand supplied to the Transmission Customer, the charge shall be the greater of a) the market price of installing leading reactive power supply expressed in terms of $/KVAR or b) $50/KVAR of installed (leading) reactive power reflecting current NSTAR cost.

For the KVAR demand absorbed by NSTAR the charge shall be the greater of a) the market price of installing lagging reactive power supply expressed in terms of $/KVAR or b) $22.5/KVAR of installed (lagging) reactive power reflecting current NSTAR cost.

SCHEDULE 3

LONG-TERM FIRM AND SHORT-TERM FIRM

LOCAL POINT-TO-POINT SERVICE

The Transmission Customer shall compensate NSTAR for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following charges as applicable:

1) Annual Rate

The Annual Rate for Firm Local Point-To-Point Service shall consist of the higher of (i) the Embedded Cost Charge or (ii) the Incremental Cost Charge, as set forth below:

(i) The Embedded Cost Charge shall be determined by dividing NSTAR's Annual Transmission Revenue Requirements (determined in accordance with Attachment D of this Local Service Schedule) by the maximum amount of NSTAR's Monthly Transmission System Load during such Service Year.

(ii) The Incremental Cost Charge shall be determined from the total costs of all Local Network Upgrades plus other incremental costs incurred provided for in the Service Agreement application to a transaction. If the Incremental Cost Charge is higher, the Transmission Customer shall pay for the facilities necessary to provide it with service during an amortization period, with the Transmission Customer paying the Embedded Cost Charge upon completion of the amortization. Such amortization period shall be coterminous with the Service Agreement.

2) Firm Local Point-To-Point Service for Monthly Transactions or Longer Term Transactions

The charge for each month applicable to a monthly transaction or longer term transaction (the "Monthly Rate") shall be determined as the product of: (a) NSTAR's Annual Rate for Firm Local Point-To-Point Service divided by twelve (12) months and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Service Agreement for such month, expressed in kilowatts.

3) Firm Local Point-To-Point Service for Less Than One Month

NSTAR's Weekly Rate is equal to NSTAR's Annual Rate for Firm Local Point-To-Point Service divided by fifty-two (52) weeks. NSTAR's Daily Rate is equal to NSTAR's Annual Rate for Firm Local Point-To-Point Service divided by three hundred and sixty-five (365) days. NSTAR's Hourly Rate is equal to

NSTAR's Annual Rate for Firm Local Point-To-Point Service divided by eight thousand seven hundred and sixty (8,760) hours.

The Transmission Customer shall pay the Weekly, Daily or Hourly Rate, as applicable, times the Reserved Capacity set forth in the Transmission Customer's Applicable Service Agreement.

4) Penalty

When the Transmission Customer exceeds its Reserved Capacity or uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved (Excess Incident), NSTAR will charge the Transmission Customer 200% of the rate determined as follows for each kilowatt of the Excess Incident:

- The unreserved use penalty for a single hour of unreserved use shall be based on the rate for daily Firm Point-to Point Transmission Service.

- If there is more than one assessment for a given duration (e.g., daily) for the Transmission Customer, the penalty shall be based on the next longest duration (e.g., weekly).

- The unreserved penalty charge for multiple instances of unreserved use (i.e., more than one hour) within a day shall be based on the daily rate for Firm Point-To-Point Transmission Service.

- The unreserved penalty charge for multiple instances of unreserved use isolated to one calendar week shall be based on the charge for weekly Firm Point-To-Point Transmission Service.

- The unreserved use penalty charge for multiple instances of unreserved use during more than one week during a calendar month shall be based on the charge for monthly Firm Point-To-Point Transmission Service.

- The unreserved use penalty charge for multiple instances of unreserved use during more than one month during a calendar year shall be based on the charge for yearly Firm Point-To-Point Transmission Service.

All Excess Incidents will be recorded by NSTAR, and if in any calendar year more than ten (10) Excess Incidents occur in connection with service for the Transmission Customer, then NSTAR may require the Transmission Customer to apply for additional Firm Local Point-To-Point Service under this Local

Service Schedule in the amount equal to the highest Excess Incident during that Service Year. Charges for such additional transmission service will relate back to the first day of the month following the month of NSTAR's notice.

5) Curtailment Penalty Charge

If the Transmission Customer fails to respond to established emergency load shedding and curtailment procedures to relieve emergencies on the Transmission System, NSTAR may assess a penalty charge to the Transmission Customer. Said penalty charge will be equal to two (2) times the Monthly Rate for Firm Local Point-To-Point Service for the month in which such service was not curtailed or interrupted.

6) Taxes and Fees Charge

A) If any governmental authority requires the payment of any fee or assessment not specifically provided for in any of the charge or rate provisions under this Local Service Schedule or imposes a sales, gross revenue, or other form of tax with respect to payments made for service provided under this Local Service Schedule, including any applicable interest charged on any deficiency assessment made by the taxing authority, together with any further tax on such payments, the obligation to make payment for any such fee, assessment, or tax shall be borne by the Transmission Customer. NSTAR will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's Regulations.

B) If NSTAR incurs tax liability currently for which it will, in subsequent years, receive tax benefits (for example, a taxable contribution in aid of construction), the Transmission Customer shall pay to NSTAR an amount sufficient to reimburse NSTAR, on a net present value basis, for the reasonably projected costs resulting from the tax liability incurred in the current year less the reasonably projected tax benefits received by NSTAR in future years.

C) If NSTAR takes a position that any particular transaction under any section of this Local Service Schedule does not constitute a transaction of the type described immediately above, and that position is subsequently reversed by Treasury ruling or regulation, or court action, then the Transmission Customer shall pay to NSTAR an amount calculated as described above but additionally taking into account any interest assessment required to be paid by NSTAR.

7) Regulatory Expense Charge

NSTAR shall have the right to make a Section 205 filing for recovery of regulatory expenses associated with this Local Service Schedule and the Service Agreement(s).

8) Customer-Related Expense Charge

NSTAR shall charge the Transmission Customer, in addition to the other charges assessed pursuant to this Local Service Schedule, and as set forth in its Service Agreement for those costs attributable to the billing, meter reading, record keeping, (all from FERC Uniform System of Accounts Nos. 901-905) and an allocation of administrative and general expenses (FERC Uniform System of Accounts Nos. 920-935) associated with each of these costs, all of which are related to the Transmission Customer's Local Point-To-Point Service and allocated on the basis of the total number of customers served by NSTAR.

9) Exchanges

With respect to any transactions that involve an exchange, each party to such transaction shall be an individual Transmission Customer under this Local Service Schedule. Accordingly, a transmission charge, as applicable, will be calculated for, and a separate bill will be rendered to, each such Transmission Customer.

10) Discounts

Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by NSTAR must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, NSTAR must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

11) Resales

The rates and rules governing charges and discounts shall not apply to resales of transmission service, compensation for which shall be governed by § I.11(a) of Schedule 21.

SCHEDULE 4

NON-FIRM LOCAL POINT-TO-POINT SERVICE

The Transmission Customer shall compensate NSTAR for any Ancillary Services and for Non-Firm Local Point-To-Point Service up to the sum of the applicable charges set forth below:

1) The Annual Rate for Non-Firm Local Point-To-Point Service shall be NSTAR's Annual Transmission Revenue Requirements (determined in accordance with Attachment D of this Local Service Schedule) for the Service Year divided by NSTAR's Monthly Transmission System Load during such Service Year.

2) Non-Firm Local Point-To-Point Service for Monthly Transactions or Longer Term Transactions
The charge for each month applicable to a monthly transaction or longer term transaction (the "Monthly Rate") shall be determined as the product of: (a) NSTAR's Annual Rate for Non-Firm Local Point-To-Point Service divided by twelve (12) months and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Service Agreement for such month, expressed in kilowatts.

3) Non-Firm Local Point-To-Point Service for Less Than One Month
NSTAR's Weekly Rate is equal to NSTAR's Annual Rate for Non-Firm Local Point-To-Point Service divided by fifty-two (52) weeks.

NSTAR's Daily Rate is equal to NSTAR's Annual Rate for Non-Firm Local Point-To-Point Service divided by three hundred and sixty-five (365) days. NSTAR's Hourly Rate is equal to NSTAR's Annual Rate for Non-Firm Local Point-To-Point Service divided by eight thousand seven hundred and sixty (8,760) hours.

The Transmission Customer shall pay the Weekly, Daily or Hourly Rate, as applicable, time the Reserved Capacity set forth in the Transmission Customer's Applicable Service Agreement.

4) Credit to the Transmission Charge
Whenever service provided hereunder is interrupted or curtailed by NSTAR, or its Designated Agent including ISO, the Transmission Charges to the Transmission Customer calculated pursuant to Sections 2 and 3 of this Schedule 4 shall be credited by an amount equal to the sum of the credits calculated for each hour of interruption or curtailment in service. The credit to the Transmission Customer for each hour of

interruption or curtailment shall be calculated as the product of (a) NSTAR's Hourly Rate and (b) the kilowatts of service interruption or curtailment during such hour.

5) Penalty

When the Transmission Customer exceeds its Reserved Capacity or uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved (Excess Incident), NSTAR will charge the Transmission Customer 200% of the rate determined as follows for each kilowatt of the Excess Incident:

- The unreserved use penalty for a single hour of unreserved use shall be based on the rate for daily Firm Point-to Point Transmission Service.
- If there is more than one assessment for a given duration (e.g., daily) for the Transmission Customer, the penalty shall be based on the next longest duration (e.g., weekly).
- The unreserved penalty charge for multiple instances of unreserved use (i.e., more than one hour) within a day shall be based on the daily rate for Firm Point-To-Point Transmission Service.
- The unreserved penalty charge for multiple instances of unreserved use isolated to one calendar week shall be based on the charge for weekly Firm Point-To-Point Transmission Service.
- The unreserved use penalty charge for multiple instances of unreserved use during more than one week during a calendar month shall be based on the charge for monthly Firm Point-To-Point Transmission Service.
- The unreserved use penalty charge for multiple instances of unreserved use during more than one month during a calendar year shall be based on the charge for yearly Firm Point-To-Point Transmission Service.

All Excess Incidents will be recorded by NSTAR, and if in any calendar year more than ten (10) Excess Incidents occur in connection with service for the Transmission Customer, then NSTAR may require the Transmission Customer to apply for additional Non-Firm Local Point-To-Point Service under this Local Service Schedule in the amount equal to the highest Excess Incident during that Service Year. Charges for such additional Non-Firm Local Point-To-Point Service will relate back to the first day of the month following the month of NSTAR's notice.

6) Curtailment Penalty Charge.

If the Transmission Customer fails to respond to established emergency load shedding and curtailment procedures to relieve emergencies on the Transmission System, NSTAR may assess a penalty charge to the Transmission Customer. Said penalty charge will be equal to two (2) times the monthly demand charge for Non-Firm Local Point-To-Point Service for the month in which such service was not curtailed or interrupted.

7) Taxes and Fees Charge

A) If any governmental authority requires the payment of any fee or assessment not specifically provided for in any of the charge or rate provisions under this Local Service Schedule or imposes a sales, gross revenue, or other form of tax with respect to payments made for service provided under this Local Service Schedule, including any applicable interest charged on any deficiency assessment made by the taxing authority, together with any further tax on such payments, the obligation to make payment for any such fee, assessment, or tax shall be borne by the Transmission Customer. NSTAR will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's Regulations.

B) If NSTAR incurs tax liability currently for which it will, in subsequent years, receive tax benefits (for example, a taxable contribution in aid of construction), the Transmission Customer shall pay to NSTAR an amount sufficient to reimburse NSTAR, on a net present value basis, for the reasonably projected costs resulting from the tax liability incurred in the current year less the reasonably projected tax benefits received by NSTAR in future years.

C) If NSTAR takes a position that any particular transaction under any section of this Local Service Schedule does not constitute a transaction of the type described immediately above, and that position is subsequently reversed by Treasury ruling or regulation, or court action, then the Transmission Customer shall pay to NSTAR an amount calculated as described above but additionally taking into account any interest assessment required to be paid by NSTAR.

8) Regulatory Expense Charge

NSTAR shall have the right to make a Section 205 filing for recovery of regulatory expenses associated with this Local Service Schedule and the Service Agreement(s).

9) Customer-Related Transaction Charge

NSTAR shall charge the Transmission Customer, in addition to the other charges assessed pursuant to this Local Service Schedule, and as set forth in its Service Agreement for those costs attributable to the billing, meter reading, record keeping, (from FERC Uniform System of Accounts Nos. 901-905) and an allocation of administrative and general expenses (Nos. 920-935) associated with each of these costs, all of which are related to the Transmission Customer's Local Point-To-Point Service and allocated on the basis of the total number of customers served by NSTAR.

10) Exchanges

With respect to any transactions that involve an exchange, each party to such transaction shall be an individual Transmission Customer under this Local Service Schedule. Accordingly, a transmission charge, as applicable, will be calculated for, and a separate bill will be rendered to, each such Transmission Customer.

11) Discounts

Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by NSTAR must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, NSTAR must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

12) Resales

The rates and rules governing charges and discounts shall not apply to resales of transmission service, compensation for which shall be governed by § I.11(a) of Schedule 21.

ATTACHMENT A

METHODOLOGY TO ASSESS AVAILABLE TRANSFER CAPABILITY

1. Introduction

ISO is the regional transmission organization ("RTO"), serving the New England Control Area. ISO is responsible for development, oversight, and fair administration of New England's wholesale market and management of bulk electric power system and wholesale markets' planning processes. The ISO serves as the Balancing Authority for the New England Control Area. The New England Control Area is interconnected to three neighboring Balancing Authority Areas: New Brunswick System Operator Area ("NBSO Area"), New York Independent System Operator Area ("NYISO Area"), and Hydro-Québec TransÉnergie Area ("HQTÉ Area").

As part of its RTO responsibilities, the ISO is registered with the North American Electric Reliability Corporation ("NERC") as several functional model entities that have responsibilities related to the calculation of ATC as defined in the following NERC Standards: MOD-001 – Available Transmission System Capability ("MOD-001"), MOD-004 – Capacity Benefit Margin ("MOD-004"), and MOD-008 – Transmission Reliability Margin Calculation Methodology ("MOD-008"). The extent of those responsibilities is based on various Commission-approved transmission operating agreements and the provisions of the ISO New England Operating Documents.

While the ISO is the transmission provider for transmission service associated with PTF, the Participating Transmission Owners (PTOs) under the Transmission Operating Agreement, such as NSTAR, provide local transmission service over Non-Pool Transmission Facilities within the RTO footprint and are responsible for calculating TTC and ATC associated with Local Service provided under Schedule 21. Pursuant to CFR § 37.6(b)[1]of the Commission's regulations, NSTAR as a Transmission Provider is obligated to calculate and post ATC and TTC for certain local facilities over which Point-to-Point transmission service is provided under Schedule 21-NSTAR. These are primarily radial paths that provide transmission service to directly interconnected generators.

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[1]§37.6(b) Posting transfer capability. The available transfer capability (ATC) on the Transmission Provider's system and the total transfer capability (TTC) of that system shall be calculated and posted for each Posted Path as set forth in this section.

Posted Path is defined as any control area-to-control area interconnection; any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a

customer requests to have ATC or TTC posted. For this last category, the posting must continue for 180 days and thereafter until 180 days have elapsed from the most recent request for service over the requested path. For purposes of this definition, an hour includes any part of any hour during which serviced was denied, curtailed or interrupted. §37.6(b)(1)(i).

NSTAR does not currently have any Posted Paths based on the above definition. However, to the extent that NSTAR does in the future have any Posted Path(s), NSTAR will calculate ATC and TTC using NERC Standard MOD-029-1 Rated System Path Methodology as outlined below.

1.1 Scope of Document

The scope of this document is limited to the following functions which are performed or utilized by NSTAR in order to provide Local Point-to Point Service under Schedule 21-NSTAR: Total Transfer Capability (TTC) methodology; Available Transfer Capability (ATC) methodology; Existing Transmission Commitment (ETC); Use of Transmission Reliability Margin (TRM); Use of Capacity Benefit Margin (CBM); and Use of Rollover Rights (ROR) in the calculation of ETC.

TTC and ATC are required to be calculated only for certain non-PTF internal paths over which Local Point-to-Point Service is provided under Schedule 21-NSTAR. TTC and ATC are not calculated by NSTAR for Local Network Service because ISO employs a market model for economic, security constrained dispatch of generation, and NSTAR does not require advance reservation for such network service.

2. Transmission Service in the New England Markets

Since the inception of the open access transmission tariff for New England, the process by which generation located inside New England supplies energy and/or capacity to the bulk electric system has differed from the Commission's pro forma open access transmission tariff. The fundamental difference is that internal generation is dispatched in an economic, security constrained manner by the ISO rather than utilizing a system of physical rights, advance reservations and point-to-point transmission service. Through this process, internal generation provides offers that are utilized by the ISO in the Real-Time Energy Market dispatch software. This process provides the least-cost dispatch to satisfy Real-Time load on the system.

In addition to offers from generation within New England, entities may submit energy transactions that move into the New England Control Area, out of the New England Control Area or through the New

England Control Area. The Real-Time Energy Market clears these External Transactions based on forecast LMPs and the transfer capability of the associated external interfaces. With those External Transactions in place, the Real-Time Energy Market dispatches internal generation in an economic, security constrained manner to meet Real-Time load within the region.

The process for submitting External Transactions into the Real-Time Energy Market does not require an advance physical reservation for use of the PTF. In the event that the net of economic External Transactions is greater than the transfer capability of the associated external interface, the ExternalTransactions selected to flow are selected based on the rules specified in the Tariff. For any External Transactions that are confirmed to flow in Real-Time based on the economics of the system, a transmission reservation for RNS and Through-or-Out Service is created after-the-fact to satisfy the transparency needs of the market.

The process described above is applicable to the PTF within the New England Control Area, and non-PTF where utilized for Local Network Service by generation or load. However, NSTAR owns local transmission facilities over which an advance transmission service reservation for firm or non-firm transmission service may be required. On those facilities, Market Participants may obtain a transmission service reservation from NSTAR under Schedule 21-NSTAR prior to delivery of energy and/or capacity into the New England markets pursuant to Schedule 18, 20A or 20B of the Tariff. This document addresses the calculation of ATC and TTC for these non-PTF internal paths.

3. NSTAR Total Transfer Capability (TTC)

TTC is the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions. TTC for Schedule 21-NSTAR is calculated using NERC Standard MOD-029-1 Rated System Path Methodology and posted on the NSTAR OASIS site.

The TTC on NSTAR's Non-PTF that requires Local Point-to-Point Service reservations are relatively static values. NSTAR calculates the TTC for Posted Paths as the rating of the particular radial transmission path.NSTAR will calculate and post TTC on its OASIS site for all non-PTF Posted Paths that are eligible for Local Point-to-Point Service reservations. TTC is calculated as the transfer capability rating of the particular radial transmission path less the most limiting element within the PostedPath.

4. Capacity Benefit Margin (CBM)

CBM is defined as the amount of firm transmission transfer capability set aside by a Transmission Provider for use by the Load Serving Entities. The ISO does not set aside any CBM for use by the Load Serving Entities, because of the New England approach to capacity planning requirements in the ISO New England Operating Documents, and in any event, ISO's determination of CBM does not apply directly to the determination of ATC for Local Service. Load Serving Entities operating with the New England Control Area are required to arrange for their Capacity Requirements prior to the beginning of any given month in accordance with the Tariff, Section III.13.7.3.1 (Calculation of Capacity Requirement and Capacity Load Obligation). Load Serving Entities do not utilize CBM to ensure that their capacity needs are met; therefore, CBM is not applicable within the New England market design. Accordingly, for purposes of NSTAR's ATC calculation and because CBM for the New England Control Area is set to zero (0), NSTAR utilizes a zero (0) CBM value.

5. Transmission Reliability Margin (TRM)

TRM is the amount of transmission transfer capability set aside to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. It is used only for external interfaces under the New England market design. As NSTAR does not have any external interfaces, TRM for its non-PTF facilities is presently set to zero.

6. Existing Transmission Commitments

6.1 Existing Transmission Commitments, Firm (ETC_F)

ETC_F are confirmed Firm Local Point-To-Point Transmission Service reservations (PTP_F) plus any exercised rollover rights for Firm Point-To-Point Transmission Service reservations (ROR_F). There are no allowances necessary for Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$), grandfathered Transmission Service (GF_F), and other services, contracts or agreements (OS_F) to be considered in the ETC_Fcalculation.

6.2 Existing Transmission Commitments, Non-Firm (ETC_{NF})

ETC_{NF} are confirmed Non-Firm transmission reservations (PTP_{NF}). There are no allowances necessary for Non-Firm Network Integration Transmission Service ($NITS_{NF}$), Non-Firm grandfathered Transmission Service (GF_{NF}), or other services, contracts or agreements (OS_{NF}).

7. Calculation of ATC for NSTAR's Transmission System

NERC Standards MOD-001-1 – Available Transmission System Capability and MOD-029-1 – Rated

System Path Methodology define the required items to be identified when describing a Transmission Provider's ATC methodology. As a practical matter, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

Common practice is not to calculate or post firm and non-firm ATC values for the Non-PTF assets, as ATC is positive and listed as 9999. Transmission Customers are not restricted from reserving Firm or Non-Firm Point-to-Point Service on Non-PTF facilities.

As Real-Time approaches, the ISO utilizes the Real-Time Energy Market rules to determine which of the submitted energy transactions will be scheduled in the coming hour. Basically, the ATC of the non-PTF assets in the New England market is almost always positive. The ATC is equal to the amount of net energy and/or capacity transactions that the ISO will schedule on an interface for the designated hour. With this simplified version of ATC, there is no detailed algorithm to be described or posted other than: ATC equals TTC. Thus, for those non-PTF that serve as a path for NSTAR's Transmission Customers taking Local Point-to-Point Service, NSTAR has posted the ATC as 9999, consistent with industry practice. ATC on these paths varies depending on the time of day. However, it is posted with an ATC of "9999" to reflect the fact that there are no restrictions on these paths for commercial transactions.

7.1 Calculation of Schedule 21-NSTAR Firm ATC (ATC_F)

7.1.1 Calculation of ATC_F in the Planning Horizon (PH)

For purposes of this Attachment A, PH is any period before the Operating Horizon.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for TRM, CBM, ETC_F, $Postbacks_F$ and $counterflows_F$. As discussed above, TRM and CBM are zero. Firm Transmission Service under Schedule 21-NSTAR that is available in the PH includes: Yearly, Monthly, Weekly and Daily. $Postbacks_F$ and $counterflows_F$ of Schedule 21-NSTAR transmission reservations are not considered in the ATC calculation. Therefore, ATC_F in the PH is equal to the TTC minus ETC_F.

7.1.2 Calculation of ATC_F in the Operating Horizon (OH)

For purposes of this Attachment A, OH begins noon eastern prevailing time each day. At that time, the OH spans from noon through midnight of the next day for a total of 36 hours. As time progresses, the total hours remaining in the OH decrease until noon the following day when the OH is once again reset to

36 hours.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for ETC_F, CBM, TRM, $Postbacks_F$ and $counterflows_F$. As discussed above, TRM and CBM are zero. Daily Firm Transmission Service under Schedule 21-NSTAR is the only firm service offered in the OH. $Postbacks_F$ and $counterflows_F$ of Schedule 21-NSTAR transmission reservations are not considered in the ATC_F calculation. Therefore, ATC_F in the OH is equal to the TTC minus ETC_F.

7.1.3 Calculation of ATC_F in the Scheduling Horizon (SH)

Because Firm Schedule 21-NSTAR transmission service is not offered in the SH, ATC_F in the SH is zero.

7.2 Calculation of Schedule 21-NSTAR Non-Firm ATC (ATC_{NF})

7.2.1 Calculation of ATC_{NF} in the PH

ATC_{NF} is the capability for Non-Firm transmission reservations that remain after allowing for ETC_F, ETC_{NF}, scheduled CBM (CBM_S), unreleased TRM (TRM_U), Non-Firm Postbacks ($Postbacks_{NF}$) and Non-Firm counterflows ($counterflows_{NF}$). As discussed above, the TRM and CBM for Schedule 21-NSTAR are zero. ATC_{NF} available in the PH includes: Monthly, Weekly, Daily and Hourly. TRM_U, $Postbacks_{NF}$ and $counterflows_{NF}$ of Schedule 21-NSTAR transmission reservations are not considered in this calculation. Therefore, ATC_{NF} in the PH is equal to the TTC minus ETC_F and ETC_{NF}.

7.2.2 Calculation of ATC_{NF} in the OH

ATC_{NF} available in the OH includes: Daily and Hourly. As discussed above, the TRM and CBM for Schedule 21-NSTAR are zero. TRM_U, $counterflows_{NF}$ and ETC_{NF} of Schedule 21-NSTAR transmission reservations are not considered in this calculation. Therefore, ATC_{NF} in the OH is equal to the TTC minus ETC_F plus postbacks of PTP_F in the OH as PTP_{NF} ($Postbacks_{NF}$).

7.3 Negative ATC

As stated above, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available. As also stated above, NSTAR’s Non-PTF are primarily radial paths that provide transmission service to directly interconnected generators. It is possible that in the future a particular radial path may interconnect more nameplate capacity generation than the path’s TTC. For the local facilities modeled by ISO, and consistent with ISO’s economic, security-constrained dispatch methodology, the ISO will only dispatch an amount of generation

interconnected to such path so as not to incur a reliability or stability violation on the subject path. Therefore, ATC in the PH, OH and SH could become zero, but will never be negative.

8. Posting of Schedule 21-NSTAR ATC

8.1 Location of ATC Posting

ATC values are posted on the NSTAR OASIS site.

8.2 Updates to ATC

When any of the variables in the ATC equations change, the ATC values are recalculated and immediately posted.

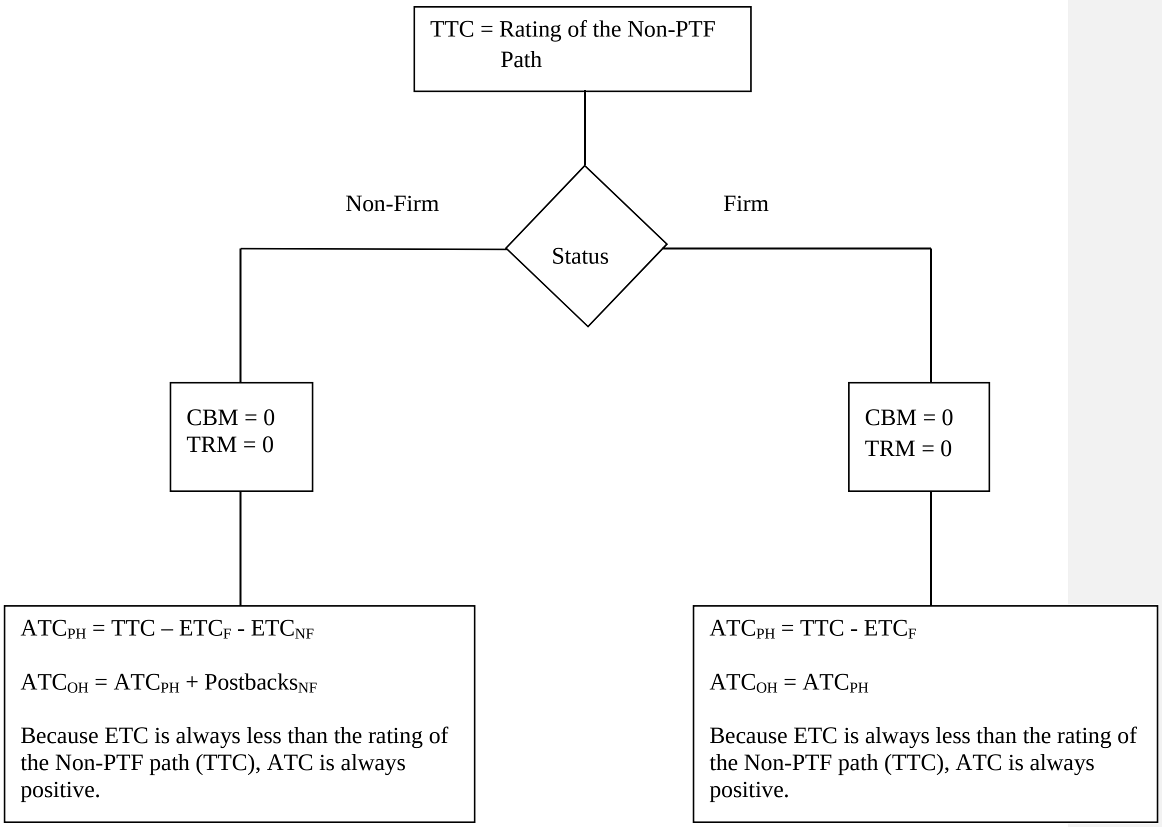
8.3 Coordination of ATC Calculations

NSTAR’s Non-PTF has no external interfaces. Therefore, it is not necessary to coordinate the values.

8.4 Mathematical Algorithms

The mathematical algorithms for the calculation of ATC can be found on NSTAR’s web site at http://www.nstar.com/business/rates_tariffs/open_access/docs/ATC_Algorithm-Sch_21.pdf

Non-PTF Transmission Path ATC Process Flow Diagram



ATTACHMENT B

METHODOLOGY FOR COMPLETING A SYSTEM IMPACT STUDY

When NSTAR determines on a non-discriminatory basis that a System Impact Study is needed because its Transmission System will be inadequate to accommodate a Completed Application for service, the following outlines the study methodology that NSTAR will employ to estimate the Transmission System impact of a Completed Application for Firm Local Point-To-Point Service, Network Integration Service and/or any costs associated with Direct Assignment Facilities and/or Local Network Upgrades that would be incurred in order to accommodate the service requested in the Completed Application.

1. System Impact will be estimated based on consideration of reliability requirements to:

- meet obligations under agreements that predate this Local Service Schedule;
- meet obligations of existing and pending Completed Application under this Local Service Schedule;
- maintain thermal, voltage and stability system performance within acceptable regional practices.

2. Guidelines and Principles followed by NSTAR: When performing the System Impact Study, NSTAR will apply the following, as amended and/or adopted from time to time.

- Good Utility Practice;
- Criteria, rules and reliability standards applicable to the New England Transmission System;
- NPCC criteria and guidelines; and
- NSTAR criteria and guidelines.

3. Transmission System Model Representation: The Transmission System model will be based on a library of load flow cases prepared by ISO for studies of the New England area. The models may include representations of other NPCC and neighboring systems. These load flow cases include individual system model representations provided by Transmission Owners and represent forecasted system conditions for up to ten (10) years into the future. This library of load flow cases is maintained and updated as appropriate by ISO, and is consistent with information filed under FERC Form 715. NSTAR will use system models that it deems appropriate for study of the Completed Application for service. Additional system models and operating conditions, including assumptions specific to a particular analysis, may be developed for conditions not available in the library of load flow cases. The system models may be modified, if necessary, to include additional system information on load, transfers and

configuration, as it becomes available.

4. System Conditions: Loading of all Transmission System elements shall be less than normal ratings for pre-contingency conditions and less than long-term emergency (LTE) ratings for post-contingency conditions. Post-contingency loading above LTE rating and less than short-term emergency (STE) rating may be allowed where demonstrated that loading can be reduced below the LTE rating within fifteen (15) minutes. Transmission System voltage shall be within the applicable design ratings of connected equipment for normal and emergency conditions. Normal and post-contingency voltages shall be in accordance with NSTAR and ISO standards.

5. Short Circuits: Transmission System short circuit currents shall be within the applicable equipment design ratings.

6. Study Analysis: System impact of the integration of new load will be evaluated to meet the requirements of design, identified in the guidelines and principles under Item 2 above, to provide sufficient transmission capability to maintain stability and to maintain thermal and voltage levels of lines and equipment within applicable limits. The same applies to the evaluation of Firm Point-To-Point Service when it has been determined that insufficient transfer capability is available and the Eligible Customer requests a System Impact Study be conducted.

7. Loss Evaluation: The impact of losses on the Transmission System will be taken into account in the System Impact Study to ensure Good Utility Practice in the design and operation of its system.

8. System Protection: Protection requirements will be evaluated by NSTAR in accordance with ISO, NPCC, and NSTAR criteria.

9. Approvals: NSTAR will conduct the System Impact Study to ensure compliance with its planning and design policies and practices. However, the actions to be taken by the Parties to implement the recommendations of the System Impact Study are subject to approval under the Tariff.

10. Study Scope and Reporting: The study will determine the impacts and identify changes required, if any, to NSTAR's existing Transmission System. NSTAR will provide the Eligible Customer with a written report of the physical interconnection alternative(s), required NSTAR system additions and/or modifications, if any, associated study grade cost estimates (+/- 25%) and the results of the analysis.

ATTACHMENT C

INDEX OF LOCAL POINT-TO-POINT SERVICE CUSTOMERS

Customer	Date of Service Agreement
AIG Trading Corporation	October 29, 1996
Altresco Pittsfield Light Plant	December 26, 1996
Aquila Power Company	February 26, 1997
Axia Energy, LP	June 20, 2001
Baltimore Gas & Electric Co.	January 14, 1997
Bangor Hydro-Electric Co.	October 1, 1996
Belmont Municipal Light Dept.	December 11, 1996
Central Vermont Public Service	January 3, 1997
Chicopee Municipal Light Dept.	October 2, 1996
CINERGY Capital and Trading, Inc.	January 1, 1998
CINERGY Operating Companies	December 1, 1997
Citizens Lehman Power Sales	November 6, 1996
Constellation Power Source, Inc.	July 11, 1997
Duke Energy Solutions, Inc.	March 19, 1999
DukeSolutions, Inc.	May 18, 1999
Edison Source	June 9, 1997
Electric Clearinghouse, Inc.	October 7, 1996
Entergy Nuclear Generation Company	April 10, 2003
Equitable Power Services Company	October 29, 1996
Green Mountain Power Corporation	January 10, 1997
HQ Energy Services (US) Inc.	February 8, 1999
LG&E Power Marketing, Inc.	October 8, 1996
Maine Public Service Company	September 30, 1996
Massachusetts Bay Transportation Authority	May 1, 1999
Massachusetts Municipal Wholesale Electric Co.	September 6, 1996
Merchant Energy Group of the Americas, Inc.	August 16, 1998
Mirant Canal, LLC	July 6, 1998
Mirant Americas Energy Marketing, LP	April 28, 2004
Montaup Electric Co.	October 15, 1996

Morgan Stanley Capital Group, Inc.	October 29, 1996
NEPOOL on Behalf of NEPOOL Participants	June 1, 1997
New England Power Company	December 30, 1996
New York State Gas & Electric Corp.	December 16, 1997
NorAm Energy Services	November 14, 1997
Northeast Energy Services, Inc.	June 17, 1997
NP Energy, Inc.	August 1, 1997
NRG Power Marketing, Inc.	January 1, 2001
NSTAR Electric Company	December 24, 1996
PECO Energy Power Team	January 3, 1997
Rainbow Energy Power Marketing	November 7, 1996
Reading Municipal Light Department	September 6, 1996
Sithe New England Holdings, LLC	January 3, 1998
Sonat Power Marketing, Inc.	November 14, 1997
Southern Energy Trading and Marketing, Inc.	March 10, 1997
Strategic Energy Ltd.	May 11, 1999
The Power Company of America	November 18, 1996
Town of Braintree Electric Light Dept.	September 6, 1996
Town of Hingham Municipal Light Plant	September 9, 1996
Town of Hull Municipal Light Plant	December 11, 1996
Trans Alta Energy Marketing	November 24, 1998
Trans Canada Power Corporation	January 27, 1997
Western Power Services, Inc.	December 24, 1996
Williams Energy Services Company	July 17, 1997
VTEC Energy, Inc.	March 24, 1998

ATTACHMENT D

ANNUAL TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirements for NSTAR ("the Company") will reflect the costs for its Transmission System, including costs attributable to those incurred by the Company in owning, leasing, maintaining and supporting the Transmission System net of revenues for transmission services provided under any other FERC accepted tariff or under any contract with other parties that provides reimbursement to the Company for transmission related services. Under no circumstances shall the Company's Local Network Service rates include costs that are charged through any other rate or tariff. The Transmission Revenue Requirements will be an annual calculation based on the estimated costs for its Transmission System during the Service Year.

The Company shall make an annual informational filing with the FERC on or before May 31 of each year which shall include a True-up of estimated costs and revenues, and actual costs and revenues for the preceding Service Year. Actual costs will be determined using data required to be reported annually in the FERC Form 1 and recorded on the Company's books in accordance with FERC's Uniform System of Accounts; unless the use of other data, such as subaccount balances, is specifically required by the provisions below, in which case an officer of the Company, shall certify that the development, accuracy and application of such other data is in accordance with the provisions of this Local Service Schedule. Such certification will be included with the annual informational filing along with adequate detail that supports the values contained within the True-up calculation. References to specific FERC Form 1 pages, line numbers and columns included in this Local Service Schedule are based on the 2006 Form 1 of the Company's predecessor entities. Subsequent FERC changes to Form 1 may be adopted to the extent they are consistent with the provisions and terms of this Local Service Schedule and not otherwise prohibited by FERC.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section II.1 of the OATT or the Local Service Schedule and as used herein have the following definitions:

A. ALLOCATION FACTORS

1. Transmission Wages and Salaries Allocation Factor shall equal the ratio of transmission-related direct wages and salaries including those of affiliated companies as reported in the

Company's annual FERC Form 1, page 354, line 21, column (b) to the Company's total direct wages and salaries including those of the affiliated companies as reported in the Company's FERC Form 1, page 354, line 28, column (b), and excluding administrative and general wages and salaries as reported in the Company's FERC Form 1, page 354, line 27, column (b).

2. Plant Allocation Factor shall equal the ratio of the sum of Transmission Plant, excluding HQ leases, plus Transmission Related Intangible and General Plant to Total Plant in Service excluding HQ Leases.

B. TERMS

Administrative and General Expense shall equal the expenses as reported in the Company's FERC Form 1, page 323, line 197, column (b), excluding Property Insurance included in FERC Account No. 924, Regulatory Commission Expense included in FERC Account No. 928, and Advertising Expense included in FERC Account No. 930.1 and excluding Merger-Related Costs included in FERC Account Nos. 920-935 (other than those in FERC Account Nos. 924, 928 and 930.1, which have already been excluded). The amount of Postretirement Benefits Other Than Pensions ("PBOP") expense in FERC Account No. 926 shall be separately stated as a footnote to the Company's FERC Form 1, page 323, line 187, column (b): Current Year and column (c): Previous Year.

Amortization of Gain on Reacquired Debt shall equal the amortization amount recorded in FERC Account No. 429.1.

Amortization of Loss on Reacquired Debt shall equal the expenses as recorded in FERC Account No. 428.1.

Amortization of Investment Tax Credits shall equal the credits as recorded in FERC Account No. 411.4.

Depreciation Expense for Transmission Plant shall equal the transmission expenses as recorded in FERC Account No. 403 as reported in the Company's annual FERC Form 1 page 336, line 7, column (f).

General Plant shall equal the gross plant balance as recorded in FERC Account Nos. 389-399.

General Plant Depreciation and Amortization Expense shall equal the general plant expenses as recorded in FERC Account Nos. 403 for depreciable items and 404 for items subject to amortization as reported in the Company's annual FERC Form 1, page 336, line 10, column (f).

General Plant Depreciation Reserve shall equal the general reserve balance as recorded in FERC Account No. 108 and reported in the Company's annual FERC Form 1, page 219, line 28, column (b).

General Plant Amortization Reserve shall equal the general reserve balance as recorded in FERC Account No. 111 and reported in the Company's annual FERC Form 1, page 200 in a footnote to line 14.

Hydro-Quebec DC Facilities (HQ Leases) shall equal the balance in capital leases as recorded in FERC Account Nos. 350-359 and FERC Account Nos. 389-399.

Intangible Plant shall equal the gross plant balance as recorded in FERC Account No. 303 as reported in the Company's annual FERC Form 1, page 205, line 4, column (g). The only allowable Intangible Plant for inclusion in the Local Service Schedule are software, patent or rights costs.

Intangible Plant Amortization Expense shall equal amortization expenses as recorded in FERC Account Nos. 404-405 as reported in the Company's annual FERC Form 1, page 336, line 1, column (f). The only allowable Intangible Plant Amortization Expense for inclusion in the Local Service Schedule is the amortization of software, patent or rights costs.

Intangible Plant Amortization Reserve shall equal the amortization reserve balance as recorded in FERC Account No. 111. The only allowable Intangible Plant Amortization Reserve for inclusion in the Local Service Schedule is that related to the amortization of software, patent or rights costs.

Merger-Related Costs shall equal NSTAR Electric's amortized merger-related costs as authorized by FERC or by state regulatory order.

Other Regulatory Assets/Liabilities - FAS 106 shall equal the net of the FAS 106 balance as recorded in FERC Account No. 182.3 and any FAS 106 balance as recorded in the FERC Account No. 254.

Other Regulatory Assets/Liabilities - FAS 109 shall equal the net of the FAS 109 asset and any FAS 109 balance liability.

Other Regulatory Assets/Liabilities – shall equal NSTAR Electric's unamortized balance of merger-related transmission costs recorded in FERC Account No. 182.3 as authorized by FERC.

Payroll Taxes shall equal those payroll expenses as recorded in the FERC Account No. 408.1.

Plant Held for Future Use shall equal the balance in FERC Account No. 105 that relates to land and land rights which have been purchased for future transmission use, or transmission related projects that were included in this account before January 1, 2007.

Prepayments shall equal the prepayment balance as recorded in FERC Account No. 165, plus any prepayment specifically related to the Company's Pension plans related to electric company operations recorded in FERC Account No. 182.3, Other Regulatory Assets.

Property Insurance shall equal the expenses as recorded in FERC Account No. 924.

Total Accumulated Deferred Income Taxes shall equal the net of the deferred tax balance as recorded in FERC Account Nos. 281-283 and 190 for those balances that are directly related to transmission, excluding those directly related to distribution or other businesses.

Total Gain on Reacquired Debt shall equal the gain as recorded in FERC Account No. 257.

Total Loss on Reacquired Debt shall equal the expenses as recorded in FERC Account No. 189.

Total Municipal Tax Expense shall equal the municipal tax expenses as recorded in FERC Account No. 408.1 as reported in the Company's annual FERC Form 1, page 263, line 10, column (i).

Total Plant in Service shall equal the total gross plant balance as recorded in FERC Account Nos. 301-399 excluding HQ Leases recorded in those accounts.

Total Transmission Depreciation Reserve shall equal the transmission reserve balance as recorded in FERC Account No. 108 as reported in the Company's annual FERC Form 1, page 219, line 25, column (b), excluding HQ-related amounts recorded in that account.

Transmission Depreciation Expense shall be the annual depreciation expense for transmission accounts computed using the following rates, as approved by FERC in Docket No. ER03-1274:

Account	Description	Rate
352	Structures and Improvements	2.19%
353	Station Equipment	2.53%
354	Towers and Fixtures	2.03%
355	Poles and Fixtures	2.25%
356	Overhead Conductors and Devices	2.19%
357	Underground Conduit	2.06%
358	Underground Conductors and Devices	2.15%
359	Roads and Trails	1.63%

Transmission Merger-Related Costs shall equal NSTAR Electric's amortized merger-related transmission costs as authorized by FERC.

Transmission Operation and Maintenance Expense shall equal all transmission-related expenses as recorded in FERC Account Nos. 560-564 and 566-576.5, and shall exclude; (i) all HQ HVDC expenses recorded in those accounts, and (ii) expenses billed to the Company by ISO-NE for Scheduling and Dispatch Service.

Transmission Plant shall equal the balance as recorded in FERC Account Nos. 350-359.1, adjusted to exclude the capital leases in the Hydro-Quebec DC Facilities (HQ Leases).

Transmission Plant Materials and Supplies shall equal the balance as assigned to transmission, as recorded in FERC Account No. 154 as reported in the Company's annual FERC Form 1, page 227, lines 5 and 8, column (c).

II. CALCULATION OF TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirement shall equal the sum of (A) Return and Associated Income Taxes, (B) Transmission Depreciation and Amortization Expense, (C) Transmission Related Amortization of Gain/Loss on Reacquired Debt, (D) Transmission Related Amortization of Investment Tax Credits, (E) Transmission Related Municipal Tax Expense, (F) Transmission Related Payroll Tax Expense, (G) Transmission Operation and Maintenance Expense, (H) Transmission Related Administrative and

General Expenses, (I) Transmission Related Integrated Facilities Charges, minus (J) Transmission Support Revenue, plus (K) Transmission Support Expense, plus (L) Transmission-Related Expense from Generators, minus (M) Transmission Rents Received from Electric Property, minus (N) Short-Term and Non-Firm Point-To-Point Service Revenues, minus (O) Regional Network Services (RNS) Revenues, minus (P) Through or Out Revenues, minus (Q) ISO-NE Scheduling and Dispatch Revenues.

A. Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate.

1. Transmission Investment Base

The Transmission Investment Base will be the year end balances of (a) Transmission Plant, plus (b) Transmission Related Intangible and General Plant, plus (c) Transmission Plant Held for Future Use, plus (d) 50 percent of Transmission Related Construction Work In Progress (CWIP), less (e) Transmission Related Depreciation and Amortization Reserve, less (f) Transmission Related Accumulated Deferred Taxes, less, (g) AFUDC Regulatory Liability, plus (h) Transmission Related Gain/Loss on Reacquired Debt, plus (i) Other Regulatory Assets/Liabilities, plus (j) Transmission Prepayments, plus (k) Transmission Materials and Supplies, plus (l) Transmission Related Cash Working Capital.

(a) Transmission Plant will equal the balance of the investment in Transmission Plant. This value excludes the capital leases in the Hydro-Quebec DC Facilities (HQ Leases).

(b) Transmission Related Intangible and General Plant shall equal the sum of the balance of investment in Intangible Plant and General Plant multiplied by the Transmission Wages and Salaries Allocation Factor.

(c) Transmission Plant Held for Future Use shall equal the land and land rights portion of the balance of Transmission-related Plant Held for Future Use (FERC Account No. 105) plus the non-land Plant Held for Future Use related to projects that were included in Account No. 105 prior to January 1, 2007 to the extent such non-land plant has not been closed to Plant In Service; such balances to be provided in conformance with the FERC Uniform System of Accounts, Instruction E, Account No. 105 which requires that "…property included in this account shall be classified according to detail accounts (301-

399)…and shall be maintained in such detail as though the property were in service."

(d) 50 Percent of Transmission Related Construction Work in Process (CWIP) shall equal the balance of Transmission related investment in FERC Account 107 multiplied by 50%, subject to any exclusions pursuant to the provisions of Section 4.1 of this Local Service Schedule.

(e) Transmission Related Depreciation and Amortization Reserve shall equal the balance of Total Transmission Depreciation Reserve as reported in the Company's annual FERC Form 1, page 219 line 25, column (b), plus the balance of Transmission Related Intangible Plant Amortization Reserve, Transmission Related General Plant Depreciation Reserve and Transmission Related General Plant Amortization Reserve. Transmission Related Intangible Plant Amortization Reserve, Transmission Related General Plant Depreciation Reserve and Transmission Related General Plant Amortization Reserve shall equal the product of (i) the sum of the Intangible Plant Amortization Reserve, General Plant Depreciation Reserve and General Plant Amortization Reserve and (ii) the Transmission Wages and Salaries Allocation Factor. The Total Transmission Depreciation Reserve balance excludes any amounts related to the capital leases in the Hydro-Quebec DC Facilities (HQ Leases).

(f) Transmission Related Accumulated Deferred Taxes shall equal the electric balance of Total Accumulated Deferred Income Taxes (for those balances that are directly related to transmission, plus the balances not directly related to other businesses), with the remaining accumulated deferred taxes not directly related to other businesses being allocated on the same basis used for the related rate base assets.

(g) AFUDC Regulatory Liability shall equal 50% of the capitalized AFUDC booked on transmission projects as recorded in FERC Account No. 254.

(h) Transmission Related Gain/Loss on Reacquired Debt shall equal the electric balance of Total Gain/Loss on Reacquired Debt multiplied by the Plant Allocation Factor.

(i) Other Transmission Related Regulatory Assets/Liabilities shall equal the electric balance of any deferred rate recovery of FAS 106 expenses multiplied by the Transmission

Wages and Salaries Allocation Factor, plus the electric balance of FAS 109 multiplied by the Plant Allocation Factor, plus NSTAR Electric's unamortized balance of merger-related transmission costs recorded in FERC Account No. 182.3 as authorized by FERC.

(j) Transmission Prepayments shall equal the electric balance of Prepayments multiplied by the Transmission Wages and Salaries Allocation Factor.

(k) Transmission Materials and Supplies shall equal the electric balance of Transmission Plant Materials and Supplies.

(l) Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of the Transmission Operation and Maintenance Expense included in Section II.G, Transmission Related Administrative and General Expenses included in Section II.H, and Transmission Support Expenses included in Section II.K.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) the Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital for Service Years ending before January 1, 2013 will be calculated based 70% upon the capital structure at the end of each year and 30% upon a pro-forma capital structure consisting of 50% debt, 0% preferred, and 50% common equity; thereafter the pro-forma capital structure will be the same as the actual capital structure, and will equal the sum of (i), (ii) and (iii) below. Notwithstanding the foregoing, for Service Years ending before January 1, 2013, NSTAR's Weighted Cost of Capital will be the lower of the blended rate as calculated herein or the actual rate.

(i) the long-term debt component, which equals the product of: the actual weighted average embedded cost to maturity of the long-term debt then outstanding; and the sum of (a) the ratio that long-term debt is to the total capital multiplied by 70%, plus (b) 50% pro-forma capital structure multiplied by 30%.

(ii) the preferred component shall be the product of: the embedded cost of preferred stock outstanding at the end of each year; and the sum of (a) the ratio that preferred stock is to the total capital multiplied by 70%, plus (b) 0% pro-forma capital structure multiplied by 30%.

(iii) the return on equity component shall be the product of: the allowed ROE of the common equity; and the sum of (a) the ratio that common equity is to the total capital multiplied by 70%, plus (b) 50% pro-forma capital structure multiplied by 30%. The allowed ROE shall be 10.57%, plus any additional incentive ROE adders as may be applied to specific investment approved by the Commission pursuant to Order No. 679, provided that the total ROE for any project, including any such ROE incentives, shall be capped by the top of the applicable zone of reasonableness determined by FERC for the relevant period. The allowed ROE shall be subject to revision at any time by unilateral filing by NSTAR under Section 205 of the FPA or by such Section 205 filing by NSTAR on a joint basis with other New England transmission owners. In either case, the revised ROE shall become effective no later than sixty days after the filing in accordance with the provisions of the FPA and also subject to any suspension or refund condition which the Commission may order pursuant to its authority under that Section. Any filing made by NSTAR to revise the ROE in compliance with a Commission order shall become effective as of the date specified in such order and shall raise no issue regarding this Local Service Schedule other than the compliance with the Commission order. The allowed ROE is also subject to revision pursuant to the authority of the Commission under Sections 205 and 206 of the FPA.

(b) Federal Income Tax shall equal

$$\frac{(A+[(C+B)/D])(FT)}{1 - FT}$$

where FT is the Federal Income Tax Rate and A is the weighted return on equity component, including preferred, as determined in Sections II.A.2.(a)(ii) and (iii) above, B is Transmission Related Amortization of Investment Tax Credits, as determined in Section II.D below, C is the equity AFUDC component of Transmission Depreciation and Amortization Expense, as defined in Section II.B below, and D is Transmission Investment Base, as determined in Section II.A.1 above.

(c) State Income Tax shall equal

$$\frac{(A+[(C+B)/D] + \text{Federal Income Tax})(ST)}{1 - ST}$$

where ST is the State Income Tax Rate, A is the weighted return on equity component, including preferred, determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section II.D below, C is the equity AFUDC component of Transmission Depreciation and Amortization Expense, as defined in Section II.B below, D is the Transmission Investment Base, as determined in II.A.1 above and Federal Income Tax is the rate determined in Section II.A.2.(b) above.

B. Transmission Depreciation and Amortization Expense shall equal the sum of (i) the Depreciation Expense for Transmission Plant and (ii) an allocation of Intangible Plant Amortization Expense and General Plant Depreciation Expense, which is calculated by multiplying the sum of (a) Intangible Plant Amortization Expense and (b) General Plant Depreciation Expenses by the Transmission Wages and Salaries Allocation Factor; less the Amortization of AFUDC Regulatory Credit as recorded in FERC Account No. 407.4.

C. Transmission Related Amortization of Gain/Loss on Reacquired Debt shall equal the electric Amortization of Gain/Loss on Reacquired Debt multiplied by the Plant Allocation Factor.

D. Transmission Related Amortization of Investment Tax Credits shall equal the electric Amortization of Investment Tax Credits multiplied by the Plant Allocation Factor.

E. Transmission Related Municipal Tax Expense shall equal the total electric municipal tax expense reported in the Company’s FERC Form 1, page 263, Local Real Estate and Personal Property Taxes, column (i), multiplied by the Plant Allocation Factor.

F. Transmission Related Payroll Tax Expense shall equal the total electric payroll tax expense reported in the Company’s FERC Form 1, page 263, Service Company Allocations and Capitalization, column (i), multiplied by the Transmission Wages and Salaries Allocation Factor.

G. Transmission Operation and Maintenance Expense shall equal the Transmission Operation and

Maintenance Expenses in Section I.B above.

H. Transmission Related Administrative and General Expenses shall equal the sum of the (1) Administrative and General Expense multiplied by the Transmission Wages and Salaries Allocation Factor, (2) Property Insurance included in FERC Account No. 924, line 156 multiplied by the Transmission Plant Allocation Factor, ~~and~~ (3) expenses included in Account No. 928(excluding Merger-Related Costs included in Account No. 928), line 160 related to (i) transmission related FERC Assessments, plus (ii) any other Federal and State transmission related expenses or assessments, plus (iii) the cost of any independent audit requested by the Mass AG as the representative for NSTAR's retail customers and (4) Transmission Merger-Related Costs. The amount of PBOP expense shall be separately stated. NSTAR commits to adhere to: (i) the Commission's PBOP policy as expressed in the Commission's December 17, 1992, Statement of Policy in Docket No. PL93-1-000, as the Commission may amend that policy from time to time in the future; and (ii) the provisions of Financial Accounting Statement 106, Employers' Accounting for Postretirement Benefits Other Than Pensions.

I. Transmission Related Integrated Facilities Charges shall equal the transmission payments to Affiliates for use of the integrated transmission facilities of those Affiliates included in FERC Account No. 565.

J. Transmission Support Revenues shall equal the revenue received for transmission support included or includable in FERC Account Nos. 454 and 456 but excluding any revenue received for use of the Company's entitlement in the Hydro-Quebec Facilities.

K. Transmission Support Expense shall equal the expense paid by the Company for transmission support included in FERC Account No. 565, but excluding expenses for the Hydro-Quebec DC Facilities.

L. Transmission-Related Expense from Generators shall equal the expenses from generators that are reflected in a filing made by the Company with the Commission under Section 205 of the Federal Power Act and accepted by the Commission for recovery under the Local Service Schedule and included or includable in FERC Account No. 565.

M. Transmission Rents Received from Electric Property shall equal any FERC Account Nos. 454 and 456 Rents from Electric Property, associated with Transmission Plant but not reflected as a credit in Transmission Support Revenues in Section II.J.

N. Short-Term and Non-Firm Point-to-Point Service Revenues shall equal the applicable wheeling revenues received for Local Point-To-Point Service provided under this Local Service Schedule, including the transmission component of the Company's Third-Party Sales, as recorded in FERC Account Nos. 447 and 456.1.

O. Regional Network Services (RNS) Revenues shall equal the Company's RNS revenues pursuant to the Tariff, as included or includable in FERC Account Nos. 454, 456 and 456.1 but excluding any incremental revenues associated with FERC-approved adders for RTO participation and new investment.

P. Through or Out Revenues shall equal the distribution of revenues received by the Company for Through or Out Service pursuant to the Tariff as included or includable in FERC Account Nos. 454 and 456.1.

Q. ISO-NE Scheduling and Dispatch Revenues shall be the amount of revenues received by the Company from ISO-NE for scheduling and dispatch services pursuant to the Tariff as included or includable in FERC Account Nos. 454, 456 and 456.1.

ATTACHMENT E

INDEX OF LOCAL NETWORK SERVICE CUSTOMERS

Customer	Date of Service Agreement
ANP Blackstone Energy Company	October 1, 2000
Entergy Nuclear Generation Company	September 1, 1999
New England Power Company	September 6, 1996
NSTAR Electric Company	December 24, 1996
Sithe New Boston LLC	September 1, 1998
Sithe Framingham LLC	September 1, 1998
Sithe Mystic LLC	September 1, 1998
Sithe Edgar LLC	September 1, 1998
Sithe West Medway LLC	September 1, 1998
Town of Braintree Municipal Light Dept.	March 1, 1997
Town of Concord Municipal Light Plant	June 21, 2002
Town of Hingham Municipal Light Plant	March 1, 1997
Town of Hull Municipal Light Plant	March 1, 1997
Town of Norwood Municipal Light Dept.	September 6, 1996
Town of Reading Municipal Light Plant	March 1, 1997
Town of Wellesley Municipal Light Plant	June 21, 2002

ATTACHMENT F

FORMULA RATE TEMPLATE

NSTAR Electric Company

Annual Local Network Service Revenue Requirement

Service Year Ended December 31, xxxx

This template does not change the other provisions of this Schedule 21. The template is not a substitute for Schedule 21 language. If an inconsistency between the Schedule 21 language and the template arises, the Schedule 21 language is controlling. The template is illustrative and the actual true-up filing as made from time to time may include format changes or reflect non-material changes required by the Uniform System of Accounts.

Sheet 1

	(a)	(b)	(c)	(d)
Line	**Description**	**Section**	**Amount**	**Reference**
1	**Investment Base**	II.A.1		
2	Transmission Plant	II.A.1.a	$ -	Sheet 3, Line 1, Col (f)
3	Transmission Related Intangible & General Plant	II.A.1.b	-	Sheet 3, Line 4, Col (f)
4	Transmission Plant Held for Future Use	II.A.1.c	-	Sheet 3, Line 5, Col (f)
5	Transmission Related Construction Work in Progress	II.A.1.d	-	Sheet 3, Line 6, Col (f)
6	Total Plant		-	Sum Lines 2 thru 5
7	Trans Related Depreciation and Amortization Reserve	II.A.1.e	-	Sheet 3, Line 12, Col (f)
8	Transmission Related Accumulated Deferred Taxes	II.A.1.f	-	Sheet 3, Line 20, Col (f)
9	AFUDC Regulatory Liability	II.A.1.g	-	Sheet 3, Line 21, Col (f)
10	Total Net Plant		-	Sum Lines 6 thru 9
11	Transmission Related Gain/Loss on Reacquired Debt	II.A.1.h	-	Sheet 3, Line 22, Col (f)
12	Other Trans Related Regulatory Assets/Liabilities	II.A.1.i	-	Sheet 3, Line ~~28~~29, Col (f)
13	Transmission Prepayments	II.A.1.j	-	Sheet 3, Line ~~29~~30, Col (f)
14	Transmission Materials & Supplies	II.A.1.k	-	Sheet 3, Line ~~30~~31, Col (f)
15	Transmission Related Cash Working Capital	II.A.1.l	-	Sheet 3, Line ~~35~~36, Col (f)
16	**Total Investment Base**		$ -	Sum Lines 10 thru 15
17	**Revenue Requirement**			
18	Investment Return and Income Taxes	II.A.2	$ -	Sheet 2, Line 39, Col (c)
19	Transmission Depreciation and Amortization Expense	II.B	-	Sheet 4, Line 7, Col (f)
20	Amortization of Gain/Loss on Reacquired Debt	II.C	-	Sheet 4, Line 8, Col (f)
21	Transmission Related Amort. of Investment Tax Credits	II.D	-	Sheet 4, Line 9, Col (f)
22	Transmission Related Municipal Tax Expense	II.E	-	Sheet 4, Line 10, Col (f)
23	Transmission Related Payroll Tax Expense	II.F	-	Sheet 4, Line 11, Col (f)
24	Transmission Operation & Maintenance Expense	II.G	-	Sheet 4, Line 30, Col (f)
25	Trans Related Administrative and General Expense	II.H	-	Sheet 4, Line ~~42~~44, Col (f)
26	Transmission Related Integrated Facilities Charges	II.I	-	Sheet 5, Line 10, Col (e)
27	Transmission Support Revenues	II.J	-	Sheet 5, Line 15, Col (e)
28	Transmission Support Expense	II.K	-	Sheet 5, Line 20, Col (e)
29	Transmission Related Expense from Generators	II.L	-	Sheet 5, Line 23, Col (e)
30	Transmission Rents Received from Electric Property	II.M	-	Sheet 5, Line 28, Col (e)
31	Short-Term and Non-Firm P-T-P Service Revenues	II.N	-	Sheet 5, Line 31, Col (e)
32	Regional Network Services (RNS) Revenues	II.O	-	Sheet 5, Line 36, Col (e)
33	Through or Out Revenues	II.P	-	Sheet 5, Line 39, Col (e)
34	ISO-NE Scheduling and Dispatch Revenues	II.Q	-	Sheet 5, Line 43, Col (e)
35	**Total LNS Revenue Requirement**		$ -	Sum Lines 18 thru 34
36	Wholesale LNS Revenues Received:			
37	Item # 1		-	
38	Item #2		-	

39	Last Item	-	
40	Total Wholesale LNS Revenue	$ -	Sum Lines 37 thru 39
41	**Total Retail LNS Revenue Requirement**	**$ -**	Line 35 - Line 40
42	Average 12 CP		
43	Sum of Monthly Peaks (kw)	-	FF1: 400.17(b)
44	Average Peak	-	Line 43 / 12
45	Annual Rate per kw	$ -	Line 35 / Line 44
46	Monthly Rate per kw	$ -	Line 45 / 12
47	Daily Rate per kw	$ -	Line 45 / 365

NSTAR Electric Company
Investment Return and Income Taxes
Service Year Ended December 31, xxxx
Sheet 2

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Line	**Description**	**Tariff Section**	**Balance**	**Capitalization Ratio ***	**Cost ***	**Weighted Cost ***	**Equity Cost**	**Reference**
1	**Weighted Cost of Capital**	II.A.2.a						
2	Long Term Debt	II.A.2.a.i	$ -		0.0000%	0.0000%		FF1: Page 112.24(c)
3	Preferred Stock	II.A.2.a.ii	-		0.0000%	0.0000%	0.0000%	FF1: Page 112.3(c)
4	Common Equity	II.A.2.a.iii	-		0.0000%	0.0000%	0.0000%	FF1: Page 112.16(c) - Line 3(c)
5	Total		$ -			0.0000%	0.0000%	Sum Lines 2 thru 4
6	**Investment Return**	II.A.2						
7	Total Investment Base		$ -					Sheet 1, Line 16, Col (c)
8	Weighted Cost of Capital		0.0000%					Line 5, Col (f)
9	Total Return on Investment		$ -					Line 7 * Line 8
10	**Federal Income Tax**	II.A.2.b						
11	A = Equity Cost		0.0000%					Line 5, Col (g)
12	B = Transmission Amortization of ITC		$ -					Sheet 1, Line 21, Col (c)
13	C = Equity AFUDC		-					FF1: Page 117.38
14	Total B + C		-					Line 12 + Line 13
15	D = Investment Base		-					Line 7
16	(B + C) / D		0.00%					Line 14 / Line 15
17	(A + [(C + B) / D]		0.00%					Line 11 + Line 16
18	FT = Federal Income Tax Rate		35.00%					Federal corporate tax rate
19	1 - FT		65.00%					1 - Line 18
20	Federal Tax Factor		0.00000%					Line 17 * Line 18 / Line 19
21	Total Federal Income Taxes		$ -					Line 15 * Line 20
22	**State Income Tax**	II.A.2.c						
23	A = Equity Cost		0.0000%					Line 5, Col (g)
24	B = Transmission Amortization of ITC		$ -					Sheet 1, Line 21, Col (c)
25	C = Equity AFUDC		-					
26	Total B + C		-					Line 24 + Line 25
27	D = Investment Base		-					Line 7
28	(B + C) / D		0.00%					Line 26 / Line 27
29	(A + [(C + B) / D]		0.00%					Line 23 + Line 28
30	ST = State Income Tax Rate		6.50%					Massachusetts corporate tax rate
31	1 - ST		93.50%					1 - Line 30
32	Federal Tax Factor		0.00000%					Line 23
33	State Tax Factor		0.00000%					(Line 29 + Line 32) * Line 30 / Line 31
34	Total State Income Taxes		$ -					Line 27 * Line 33
35	**Investment Return and Income Taxes**	II.A.2						
36	Return on Investment		$ -					Line 9

37	Federal Income Taxes	-	Line 21
38	State Income Taxes	-	Line 34
	Total Return and Income		
39	**Taxes**	**$ -**	Sum Lines 36 thru 38

* Note that weighting and cost are determined on Sheet 7

NSTAR Electric Company
Investment Base
Service Year Ended December 31, xxxx
Sheet 3

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Tariff				**Allocations**	
						LNS	
Line	**Description**	**Section**	**Total**	**Allocator**	**Factor**	**Amount**	**Reference**
1	**Transmission Plant**	II.A.1.a	$ -	Direct	100.0000%	-	FF1: Page 207.58(g)
2	General Plant		-	W&S	0.0000%	-	FF1: Page 207.99(g)
3	Intangible Plant		-	W&S	0.0000%	-	FF1: Page 205.5(g)
4	**Total Intangible & General Plant**	II.A.1.b	-			-	Sum Lines 2 thru 3
5	**Transmission Plant Held for Future Use**	II.A.1.c	-	Direct	100.0000%	-	FF1: Page 214.10&.23(d)
6	**Transmission Related CWIP**	II.A.1.d	-	CWIP	50.0000%	-	FF1: Page 216(b) Trans only
7	**Transmission Related Dep & Amort Reserve**	II.A.1.e					
8	Transmission Accumulated Depreciation		-	Direct	100.0000%	-	FF1: Page 219.25(b)
9	General Plant Accumulated Depreciation		-	W&S	0.0000%	-	FF1: Page 219.28(b)
10	General Plant Accumulated Amortization		-	W&S	0.0000%	-	FF1: Page 200.21(c) Footnote
11	Intangible Plant Accumulated Amortization		-	W&S	0.0000%	-	FF1: Page 200.21(c) Footnote
12	Total Transmission Related Depreciation Reserve		-			-	Sum Lines 8 thru 11
13	**Transmission Accumulated Deferred Taxes**	II.A.1.f					
14	Accumulated Deferred Taxes (190)		-		0.0000%	-	Sheet 8, Line 5, col (d)
15	Accumulated Deferred Income Taxes (281)		-			-	FF1: Page 113.62(c)
16	Accumulated Deferred Taxes - Property (282)		-				FF1: Page 275.9(k)
17	Less Transition Property		-				FF1: Page 275.4(k)
18	Net Acc. Def. Income Taxes - Other Property (282)		-	Plant	0.0000%	-	Sum Lines 16 thru 17
19	Accumulated Deferred Income Taxes - Other (283)		-		0.0000%	-	Sheet 8, Line 10, col (d)
20	Total					-	Sum Lines 17 thru 19
21	**AFUDC Regulatory Liability**	II.A.1.g	-	Direct	100.00%	-	FF1: Page 278.6(f)
22	**Gain/Loss on Reacquired Debt**	II.A.1.h	-	Plant	0.0000%	-	FF1: Page 111.81(c)+113.61(c)
23	**Other Regulatory Assets**	II.A.1.i					
24	Merger Costs			Direct	100.00%		FF1: Page 232
~~24~~25	FAS 106 (182.3 & 254)		-	W&S	0.0000%	-	FF1: Page 232.1.39(f)+278.(f)
~~25~~26	FAS 109 (182.3 & 254)		-				FF1: Page 232.1.29(f)
~~26~~27	Less FAS 109 - Liability (182.3 & 254)		-				FF1: Page 278.2(f)
~~27~~28	Net FAS 109 (182.3 & 254)		-	Plant	0.0000%	-	Sum Lines ~~25~~ 26 thru ~~26~~ 27

~~28~~29	Total Other Regulatory Assets		-			-	Line 24 + Line 25 + line 2~~27~~8
~~29~~30	**Prepayments**	II.A.1.j	-	W&S	0.0000%	-	FF1: Page 111.57(c)+ 232.2.8(f)
~~30~~31	**Transmission Materials & Supplies**	II.A.1.k	-	Direct	100.0000%	-	FF1: Page 227.8(c)+227.5(c) Trans
~~31~~32	**Cash Working Capital**	II.A.1.l					
~~32~~33	Operation & Maintenance Expense		-	WC	12.50%	-	Sheet 1, Line 24, col (c)
~~33~~34	Administrative & General Expense		-	WC	12.50%	-	Sheet 1, Line 25, col (c)
~~34~~35	Transmission Support Expenses		-	WC	12.50%	-	Sheet 1, Line 28, col (c)
~~35~~36	Total Cash Working Capital		-			-	Sum Lines ~~32~~ 33 thru ~~33~~ 35

		Allocation	
~~36~~37	**Description**	**Factor**	**Reference**
~~37~~38	Direct Allocation (Direct)	100.0000%	
~~38~~39	Wages & Salary (W&S)	0.0000%	Sheet 6, Line 6(c)
~~39~~40	Plant Allocation (Plant)	0.0000%	Sheet 6, Line 14(c)
~~40~~41	Construction Work in Progress Allocation (CWIP)	50.0000%	Sheet 6, Line 15(c)
~~41~~42	Cash Working Capital (WC)	12.50%	Tariff Section II.A.1.l

NSTAR Electric Company
Transmission Expenses
Service Year Ended December 31, xxxx
Sheet 4

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Tariff		Allocations			
Line	Description	Section	Total	Allocator	Factor	LNS Amount	Reference
1	**Transmission Depreciation Expense**	II.B					
2	Transmission Depreciation	II.B.i		Direct	100.00%	$ -	FF1: Page 336.7(f)
3	General Plant Depreciation and Amortization	II.B.ii		W&S	0.00%	-	FF1: Page 336.10(f)
4	Amortization of Transmission Related Intangible Plant			W&S	0.00%	-	FF1: Page 336.1(f)
5	Amortization of AFUDC Regulatory Credit		-			-	FF1: Page 278.6(d) (amort)
6	Net Amortization of Transmission Related Intangible Plant		-			-	Sum Lines 4 and 5
7	Total Transmission Depreciation Expense		$ -			$ -	Sum Lines 2, 3 and 6
8	**Amortization of Gain/Loss on Reacquired Debt**	II.C		Plant	0.00%	$ -	FF1: Page 117.64c
9	**Transmission Related Amortization of ITC**	II.D		Plant	0.00%	$ -	FF1: Page 114.19(c)
10	**Transmission Related Municipal Tax Expense**	II.E		Plant	0.00%	$ -	FF1: Page 263.5(i)
11	**Transmission Related Payroll Tax Expense**	II.F		W&S	0.00%	$ -	FF1: Page 263.8i
12	**Transmission Operation and Maintenance Expense**	II.G					
13	Operation Supervision & Engineering (560)			Direct	100.00%	$ -	FF1: Page 321.83(b)
14	Load Dispatching (561)		-	Internal Costs		-	FF1: Page 321.83(b)
15	Load Dispatch - Reliability (561.1)		-	Internal Costs		-	FF1: Page 321.85(b) footnote
16	Load Dispatch-Mon and Oper Trans System (561.2)		-	Internal Costs		-	FF1: Page 321.86(b) footnote
17	Load Dispatch-Trans Service and Scheduling (561.3)		-	Internal Costs		-	FF1: Page 321.87(b) footnote
18	Scheduling, System Control and Dispatch Services (561.4)		-	Internal Costs		-	FF1: Page 321.88(b) footnote

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19	Reliability, Planning and Standards Development (561.5)		-	Internal Costs		-	FF1: Page 321.89(b)
20	Transmission Service Studies (561.6)		-	Internal Costs		-	FF1: Page 321.90(b)
21	Generation Interconnection Studies (561.7)		-	Internal Costs		-	FF1: Page 321.91(b)
22	Reliability, Planning and Standards Development (561.8)		-	Internal Costs		-	FF1: Page 321.92(b) footnote
23	Station Expenses (562)		-	Direct	100.00%	-	FF1: Page 321.93(b)
24	Overhead Lines Expenses (563)		-	Direct	100.00%	-	FF1: Page 321.94(b)
25	Underground Lines Expenses (564)		-	Direct	100.00%	-	FF1: Page 321.95(b)
26	Miscellaneous Transmission Expenses (566)		-	Direct	100.00%	-	FF1: Page 321.97(b)
27	Rents (567)		-	Direct	0.00%	-	Sheet 5, Line 7, col (d)
28	Transmission Maintenance (568 - 573)		-	Direct	100.00%	-	FF1: Ppage 321.111(b)
29	Regional Market Expense (575)		-	Internal Costs	0.00%	-	FF1: Ppage 322.131(b)
30	Total Transmission O&M Expense		$ -			$ -	Sum Lines 13 thru 28
31	**Transmission Related A&G Expenses**	II.H					
32	Administrative and General Expenses		$0				FF1: Page 323.197(b)
33	Property Insurance (924)		-				FF1: Page 323.185(b)
34	Employee Pension and Benefits (926)		-				FF1: Page 323.187(b)
35	Regulatory Commission Expense (928)		-				FF1: Page 323.189(b)
36	General Advertising Expense (930.1)		-				FF1: Page 323.191(b)
37	Merger Related Costs		-				FF1: Page 320 FN
~~37~~38	Sub-Total		-	W&S	0.00%	-	Sum Lines 32 thru ~~36~~ 37
~~38~~39	Property Insurance (924)	II.H.2	-	Plant	0.00%	-	Line 33
~~39~~40	Employee Pension and Benefits (926) - Note 1	II.H.1	-	W&S	0.00%	-	Line 34
~~40~~41	Regulatory Commission Expense (928)	II.H.3	-	Footnote	0.00%	-	Line ~~57~~ 59
~~41~~42	General Advertising Expense (930.1)	II.H	-		0.00%	-	Line 36
43	Transmission Merger Related Costs		-	Direct	100.00%	-	FF1: Page 320 FN
44~~42~~	Total Transmission Related A&G Expenses		$ -			$ -	Sum Lines ~~37~~ 39 thru 4~~41~~3
45~~43~~	Regulatory Commission Expense (928)	II.H.3					
46~~44~~	DPU - General Assessment		$ -		0.00%	$ -	FF1: Page 350.1 (d)
47~~45~~	DPU - Appropriation Account		-		0.00%	-	FF1: Page 350.2 (d)
48~~46~~	DPU - AGO Assessment #1		-		0.00%	-	FF1: Page 350.3 (d)

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49~~47~~	DPU - AGO Assessment #2		-		0.00%	-	FF1: Page 350.4 (d)
50~~48~~	DPU - Outage Reporting Assessment		-		0.00%	-	FF1: Page 350.5 (d)
51~~49~~	DPU - Manhole Cover Assessment		-		0.00%	-	FF1: Page 350.6 (d)
52~~50~~	DPU - Stray Voltage Assessment		-		0.00%	-	FF1: Page 350.7 (d)
53~~51~~	MA Emergency Management Agency		-		0.00%	-	FF1: Page 350.8 (d)
54~~52~~	FERC Assessment		-	Direct	100.00%	-	FF1: Page 350.9 (d)
55~~53~~	FER LICAP Docket		-	Direct	100.00%	-	FF1: Page 350.10 (d)
56~~54~~	FERC RMR Docket		-	Direct	100.00%	-	FF1: Page 350.11 (d)
57~~55~~	FERC Docket ER07-549, Including cost of audit		-	Direct	100.00%	-	FF1: Page 350.12 (d)
58~~56~~	DPU Regulatory Proceeding Costs 05-85		-		0.00%	-	FF1: Page 350.13 (d)
59~~57~~	Total Regulatory Commission Expenses	II.H.3	-		0.00%	-	Sum Lines ~~44~~ 46 thru ~~56~~ 58

		Allocation	
~~58~~	**Description**	**Factor**	**Reference**
60~~59~~	Direct Allocation (Direct)	100.0000%	
61~~60~~	Wages & Salaries Allocation (W&S)	0.0000%	Sheet 6, Line 6(c)
62~~61~~	Plant Allocation (Plant)	0.0000%	Sheet 6, Line 14(c)

63~~62~~ **Note 1**

64~~63~~ Included in the Employee Pension and Benefits Expenses are costs related to Post Retirement Benefits other than Pension (PBOP). PBOP costs are determined

65 by an independent actuary as required by FASB 106. The PBOP expense included in Account 926 for 20xx was $xx,xxx,xxx as compared to $xx,xxx,xxx in the prior year;

66~~64~~ as shown

67~~65~~ on the FF1, Page 323, footnote. Applying the labor allocator to the total PBOP expense results in $x,xxx,xxx of PBOP expense being recovered through the LNS Tariff

68~~66~~ in 20xx as compared to $x,xxx,xxx in the prior year.

NSTAR Electric Company

Support Expense & Revenue Detail

Service Year Ended December 31, xxxx

Sheet 5

	(a)	(b)	(c)	(d)	(e)
		Tariff			
Line	Description	Section	Amount	Includable Amount	Reference
1	Transmission Rents (Account 567)	II.G			
2	Hydro Quebec DC Phase I Support			-	FF1: Page 320.98 (b) Footnote
3	Hydro Quebec DC Phase II Support			-	FF1: Page 320.98 (b) Footnote
4	New England Power Support			-	FF1: Page 320.98 (b) Footnote
	Hydro Quebec Phase II NEP AC, Chester				
5	SVC			-	FF1: Page 320.98 (b) Footnote
6	Transmission Line Rents		-	-	FF1: Page 320.98 (b) Footnote
7	Total Transmission Rents Received		-	-	Sum Lines 2 thru 6
	Transmission Related Integrated Facilities				
8	Charges	II.I	-	-	
9	- none -		-	-	
10	Total Trans Related Integrated Facilities Charges		-	-	Sum Lines 9 thru 9
11	Transmission Support Revenues 456 & 456.1	II.J			
12	Item #1			$ -	FF1: Page 300.21(b) Footnote
13	Item # 2			-	FF1: Page 300.21(b) Footnote
14	Last Item		-	-	FF1: Page 300.22(b) Footnote
15	Total Short Term & Non-Firm PTP Revenues		$ -	$ -	Sum Lines 12 thru 14
16	Transmission Support Expense (565)	II.K			
17	Item #1			-	FF1 Q2: Page 332.2(h)
18	Item # 2			-	FF1 Q3: Page 332.2(h)
19	Last Item		-	-	FF1: Page 332.2(h)
20	Total Transmission Support Expense		-	-	Sum Lines 17 thru 19
21	Transmission Related Expense from Generators	II.L			N/A
22	- none -		-	-	
23	Total Trans Related Expense from Generators		-	-	Sum Lines 22 thru 22
24	Rents Received from Electric Property (454)	II.M			
25	Item #1			-	FF1: Page 300.19(b) Footnote
26	Item # 2			-	FF1: Page 300.19(b) Footnote
27	Last Item		-	-	FF1: Page 300.19(b) Footnote
28	Total Rents Received		-	-	Sum Lines 25 thru 27
29	Short-Term and Non-Firm Point-to-Point Rev	II.N	$ -	$ -	N/A
30	- none -		-	-	
31	Total ST and Non-Firm Point-to-Point Revenues		-	-	Sum Lines 30 thru 30
32	Regional Network Service Revenues (456):	II.O			
33	RNS Transmission Revenue		-	-	
34	RNS PTF Post 2003 investment 1 % Adder		-	-	RNS Revenue Requirement
35	RNS PTF RTO Participation 0.5% Adder		-	-	RNS Revenue Requirement

36	Total Regional Network Services Revenues		-	-	Sum Lines 33 thru 35
37	Through or Out Revenues	II.P	$ -	$ -	N/A
38	- none -		-	-	
39	Total Through or Out Revenue		-	-	Sum Lines 38 thru 38
40	ISO-NE Scheduling & Dispatch Revenue	II.Q			
41	Nepool Scheduling & Dispatch Revenue		-	-	
42	RTO Participation 0.5% Adder		-	-	Reguional Schedule 1 Revenue Requirement
43	Total ISO-NE Scheduling & Dispatch Revenue		-	-	Sum Lines 42 thru 42

NSTAR Electric Company

Allocation Factors

Service Year Ended December 31, xxxx

Sheet 6

	(a)	(b)	(c)	(d)
Line	**Description**	**Tariff Section**	**Amount**	**Reference**
1	**Transmission Wages & Salaries Allocation Factor**	I.A.1		
2	Transmission Related Direct Wages & Salaries		$ -	FF1: Page 354.21(b)
3	Total Direct Wages & Salaries		-	FF1: Page 354.28(b)
4	Administrative & General Wages & Salaries		-	FF1: Page 354.27(b)
5	Net Total Direct Wages & Salaries		-	Line 3 less Line 4
6	Transmission Wages & Salaries Allocation Factor		**0.0000%**	Line 2 / Line 5
7	**Plant Allocation Factor**	I.A.2		
8	Transmission Plant Investment		$ -	FF1: Page 207.58(g)
9	HQ Leases		-	
10	Transmission Related General Plant		-	Sheet 3, Line 2, Col (f)
11	Transmission Related Intangible Plant		-	Sheet 3, Line 3, Col (f)
12	Total Transmission Plant Investment		-	Sum Lines 8 thru 11
13	Total Plant in Service		-	FF1: Page 207.104(g)
14	Plant Allocation Factor		**0.0000%**	Line 12 / Line 13

15	**Construction Work in Progress Allocation Factor**	II.A.1.d	**50.0000%**

NSTAR Electric Company

Cost of Long Term Debt

Service Year Ended December 31, xxxx

Sheet 7

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	FF1:256(a)	FF1:256(d)		FF1:256(e)	FF1:256(b)	FF1:256(h)		FF1:256(c)					
		Long Term Debt				Principal		Debt	Call				
			Term	Coupon	Original	Amount	Percent	Disc &	Premium on	Net	Cost to	Weighted	
Line	Series	Dated	(Years)	Rate	Issue	Outstanding	of Total	Exp	Debt	Proceeds	Maturity	Cost	Reference
							Col f / Col f Total			**Col f - Col h - Col i**	**Col d + ((Col h + Col i) / (Col e / Col d))**	Col h * Col g	
1	MIFA Bonds	2/8/94	20	5.75%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
2	4.875% Debentures	4/13/04	10	4.875%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
3	7.8% Debentures	5/10/95	15	7.80%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
4	4.875 Debentures	10/9/02	10	4.875%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
5	5.75% Debentures	3/13/06	30	5.750%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
6	5.625% Debentures	11/19/07	10	5.63%			0.00%				0.0000%	0.0000%	FF1: Page 256 & 257
7	Total				$ -	$ -	0.00%	$ -	$ -	$ -		0.0000%	Sum Lines 1 Thru 6

Cost of Preferred Stock

	FF1:250(a)			FF1:250(a)		FF1:250(f)			
		Preferred Stock				Principal			
				Coupon	Original	Amount	Percent	Weighted	
	Series	Dated	Term	Rate	Issue	Outstanding	of Total	Cost	Reference
8	4.25%	6/13/1956	N/A	4.25%			0	0.0000%	FF1: Page 250 & 251
9	4.78%	7/10/1958	N/A	4.78%			0	0.0000%	FF1: Page 250 & 251
10	Total				$ -	$ -	0.00%	0.0000%	Sum Lines 8 Thru 9

Effective NSTAR ROI

Tariff Section II.A.2.a

	(a)	(b)	(c)	(d)	(e)	(f)
Line	**Description**	**Common**	**Preferred**	**LTD**	**Total**	**Reference**
11	Amount				$ -	Sheet 2, lines 2 thru 4
12	Cost	0.0000%	0.0000%	0.0000%		See Note
13	Actual Weighting	0.0000%	0.0000%	0.0000%	0.0000%	Line 11 / Total Line 11
14	Weighted Cost	0.0000%	0.0000%	0.0000%	0.0000%	Line 12 * Line 13
15	70% of Weighted Cost	0.0000%	0.0000%	0.0000%		Line 14 * 70%
16	Tariff Weighting	50.0000%	0.0000%	50.0000%	100.0000%	Tariff Section II.A.2.a
17	Weighted Cost	0.0000%	0.0000%	0.0000%	0.0000%	Line 12 * Line 16
18	30% of Weighted Cost	0.0000%	0.0000%	0.0000%		Line 17 * 30%
19	Blended Cost of Capital	0.0000%	0.0000%	0.0000%	0.0000%	Line 15 + Line 18

20	**Lower of Blended or Actual**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	Lower of line 14, col (e) or line 19, col (e)
						Tariff Section II.A.2.a
21	<u>Note:</u>					
22	The Regurn on Equity component is specified in Tariff Section II.A.2.a.iii					
23	The Cost of Preferred Stock is calculated on line 10					
24	The Cost of Long Term Debt is calculated on line 7					

NSTAR Electric Company

Annual Local Network Service Revenue Requirement

Service Year Ended December 31, xxxx

Sheet 8

Transmission Related ADIT - Tariff Section II.A.1.f

Line	(a) Description	(b) Amount	(c) Allocator	(d) Rate Base	(e) Notes
1	**Account 190**				
2	Item # 1		0.0000%	$ -	FF1: Page 234.2(c) Footnote
3	Item #2		0.0000%	-	FF1: Page 234.2(c) Footnote
4	Last Item	-	0.0000%	-	FF1: Page 234.2(c) Footnote
5	Total 190	$ -	0.0000%	$ -	Sum Lines 2 thru 4
6	**Account 283**				
7	Item # 1		0.0000%	-	FF1: Page 276.3(k) Footnote
8	Item #2		0.0000%	-	FF1: Page 276.3(k) Footnote
9	Last Item	-	0.0000%	-	FF1: Page 276.3(k) Footnote
10	Total 283	$ -	0.0000%	$ -	Sum Lines 7 thru 9
11	Wages & Salary Allocator	0.0000%			Sheet 6, Line 6, Col (d)
12	Plant Allocator	0.0000%			Sheet 6, Line 14, Col (d)

ATTACHMENT L

CREDITWORTHINESS POLICY

I. General Information:

This Attachment L details the specific requirements for the creditworthiness procedures of NSTAR. All customers taking (i) any service under Schedule 21-NSTAR or (ii) any FERC-regulated interconnection service from NSTAR must meet the terms of this Policy (where all the above, collectively, are referred to as "Services"). The creditworthiness of each customer must be established prior to receiving service from NSTAR. A customer will be evaluated at the time its application for service is provided to NSTAR. A credit review shall be conducted for each transmission customer not less than annually or upon reasonable request by the transmission customer. This Attachment L, when updated, will be done so in accordance with Section 10 of this Policy and as posted on NSTAR's OASIS.

All customers must comply with the terms of this Attachment L. Each customer should refer to NSTAR's web site at www.nstar.com, or NSTAR's OASIS site, for the NSTAR representative to whom to forward the information required by this Attachment L.

Upon receipt of a customer's information, NSTAR will review it for completeness and will notify the customer if additional information is required. Upon completion of an evaluation of a customer, NSTAR will notify the customer of its Financial Assurance requirements. NSTAR will provide a written evaluation, upon request, to customers who are not required to provide Financial Assurance.

II. Financial Information:

Customers receiving transmission service or requesting interconnection service must submit, if available, the following:

- All current rating agency reports from Standard and Poor's ("S&P"), Moody's and/or Fitch of the customer.
- Audited financial statements provided by a registered independent auditor for the two most recent years, or the period of its existence, if shorter, for the customer.

III. Creditworthiness Requirements:

A. The customer must meet at least one of the following quantitative criteria in order to receive unsecured credit equivalent to 3 months of transmission charges or, for interconnections, the credit equivalent of 3 months of the annual facilities charges and other ongoing charges:

i) If rated, the customer must have either for itself or for its outstanding debt the following:

- Standard and Poor's or Fitch rating of at least a BBB, or
- Moody's rating of at least a Baa2.

ii) If un-rated or if rated below BBB/Baa2, as stated in a), the customer must meet all of the following:

- A Current Ratio of at least 1.0 times (current assets divided by all current liabilities);
- A Total Capitalization Ratio of less that 60% debt: total debt (including all short-term borrowing) divided by total shareholders' equity plus total debt;
- "Earnings before interest, taxes, depreciation and amortization" in most recent fiscal quarter divided by expense for interest" (EBITDA-to-Interest Expense Ratio) of at least 2.0 times; and
- Audited Financial Statement with an unqualified audit opinion.

iii) If the customer relies on the creditworthiness of a parent company, the customer's parent company must meet the criteria set out in (a) or (b) above, and must provide to NSTAR a written guarantee that it will be unconditionally responsible for all financial obligations associated with the customer's receipt of transmission service from NSTAR.

iv) If the customer is a municipal that is a member of the Massachusetts Municipals Wholesale Electric Cooperative (MMWEC), MMWEC must meet the criteria set out in (a) or (b) above and provide to NSTAR a written guarantee that MMWEC will be unconditionally responsible for all financial obligations associated with the customer's receipt of transmission service from NSTAR.

B. If the customer does not qualify for unsecured credit under Section A, the customer will qualify

for unsecured credit equivalent to two months of transmission service charges, or for interconnections, the credit equivalent of two months of the annual facilities charges and other ongoing charges, if one of the following qualitative factors is met:

- ? The customer has, on a rolling basis, 12 consecutive months of payments to NSTAR with no missed, late or defaults in payment; or
- ? The customer has an executed long-term contract for the sale of the full output (energy and capacity) of its generating unit and either has executed a corresponding service agreement under Schedule 21-NSTAR for the transmission of that output or the execution of such a service agreement is pending the customer's demonstration of creditworthiness pursuant to this Attachment L.

IV. Financial Assurance:

If the customer does not meet the applicable requirements for Creditworthiness set out in Section III above, then the customer must either:

- Pay in advance for service an amount equal to the lesser of the total charge for Transmission Service or the charge for three months of Transmission Service not less than 5 days in advance of the commencement of service; or

- Obtain Financial Assurance in the form of a: letter of credit, performance bond, or corporate guarantee equal to the equivalent of 3 months of Transmission Service charges prior to receiving service.

If the customer pays for service in advance, NSTAR will pay to the customer interest on the amounts not yet due to NSTAR , computed in accordance with the Commission's regulations at 18 CFR ? 35.19a(a)(2)(iii).

V. Contesting Creditworthiness Determination:

The Transmission Customer may contest NSTAR's determination of creditworthiness by submitting a written request for re-evaluation within 20 calendar days of being notified of the creditworthiness determination. Such request should provide information supporting the basis for a request to re-evaluate a

Transmission Customer's creditworthiness. NSTAR will review and respond to the request within 20 calendar days.

VI. Process for Changing Credit Requirements:

In the event that NSTAR plans to revise its requirements for credit levels or collateral requirements as detailed in this Attachment L, NSTAR shall submit such changes in a filing to the Commission under Section 205 of the Federal Power Act. NSTAR shall follow the notification requirements pursuant to Section 3.04(a) of the Transmission Operating Agreement and reflected herein.

A. General Notification Process

i) NSTAR shall provide written notification to ISO-NE and stakeholders of any filing described above, at least 30 days in advance of such filing.

ii) Filing notifications shall include a detailed description of the filing, including a redlined document containing revised change(s).

iii) NSTAR shall consult with interested stakeholders upon request.

iv) Following Commission acceptance of such filing and upon the effective date, NSTAR shall revise Attachment L and an updated version of Schedule 21-NSTAR shall be posted the ISO-NE website.

B. Transmission Customer Responsibility

When there is a change in requirements pursuant to this Attachment L, it is the responsibility of the customers to forward updated financial information to NSTAR at the address noted on NSTAR's OASIS site and indicate whether the change affects their ability to meet the requirements of this Attachment L. In such cases where the customer's status has changed, the customer must take the necessary steps to comply with the revised requirements of the Attachment L by the effective date of the change.

VII. Posting Collateral Requirements:

A. Changes in Customer's Financial Condition

Each customer must inform NSTAR, in writing, within five (5) business days of any material change in its financial condition, and, if the customer qualifies under Section III.A(c), that of its parent company. A material change in financial condition may include, but is not limited to, the following:

- Change in ownership by way of a merger, acquisition or substantial sale of assets;
- A downgrade of long- or short-term debt rating by a major rating agency;
- Being placed on a credit watch with negative implications by a major rating agency;
- A bankruptcy filing;
- Any action requiring filing of a Form 8-K;
- A declaration of or acknowledgement of insolvency;
- A report of a significant quarterly loss or decline in earnings;
- The resignation of key officer(s);
- The issuance of a regulatory order and/or the filing of a lawsuit that could materially adversely impact current or future financial results.

B. Change in Creditworthiness Status

- A customer who has been extended unsecured credit under this policy must comply with the terms of Financial Assurance in Section IV above if one or more of the following conditions apply:
- The customer no longer meets the applicable criteria for Creditworthiness in Section III above;
- The customer exceeds the amount of unsecured credit extended by NSTAR, in which case Financial Assurance equal to the amount of excess must be provided within 5 business days; or
- The customer has missed two or more payments for any of the services offered by NSTAR in the last 12 months.

In the event that NSTAR determines that there is a change in the credit level or collateral requirements, the customer may request a written explanation of the basis for this change. Such notification should be

sent to the NSTAR contact indicated on the NSTAR OASIS site. NSTAR shall respond to such request within 20 days of receipt of such notification.

Unless otherwise noted above, when there is a change in a customer's Creditworthiness Status requiring the customer to provide Financial Assurance, the customer must provide such Financial Assurance within 20 business days from the date the customer either notifies NSTAR, as required in Section VI.B above, or receives notice from NSTAR.

VIII. Ongoing Financial Review:

Each customer is required to submit to NSTAR annually or when issued, as applicable:

- Current rating agency report;
- Audited financial statements from a registered independent auditor; and
- 10-Ks and 8-Ks, promptly upon their issuance.

IX. Suspension of Service:

NSTAR may immediately suspend service (with notification to Commission) to a customer, and may initiate proceedings with Commission to terminate service, if the customer does not meet the terms described in Sections III through VIII above at any time during the term of service or if the customer's payment obligations to NSTAR exceed the amount of unsecured or secured credit to which it is entitled under this Attachment L. A customer is not obligated to pay for transmission service that is not provided as a result of a suspension of service.

Eversource

SCHEDULE 21-ES

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SCHEDULE 21-ES

LOCAL SERVICE SCHEDULE

This Local Service Schedule, designated Schedule 21-ES, governs the terms and conditions of service taken by Transmission Customers over the Transmission System of The Connecticut Light and Power Company, Public Service Company of New Hampshire and Western Massachusetts Electric Company (together, "Eversource"), but not over the Transmission System of their affiliate, NSTAR Electric Company, which provides service pursuant to Schedule 21-NSTAR.

I. COMMON SERVICE PROVISIONS

1 Definitions

Capitalized terms not defined herein shall have the meanings given them in the Tariff.

1.1 Annual Transmission Costs

The total annual cost of the Transmission System for purposes of Local Network Service shall be the amount specified in Attachments ES-H and ES-I, until amended by Eversource or modified by the Commission.

1.2 Annual True Up

The reconciliation to actual costs and actual loads of the estimated costs and loads costs used for billing purposes under Section 3.0 of this Local Service Schedule for any Service Year.

1.3 Category A Load Ratio Share

Ratio of a Transmission Customer's Category A Network Load to Eversource's total load computed in accordance with Sections 16.5 and 16.6 under Part III of this Local Service Schedule and calculated on a rolling twelve month basis. Also referred to as "Load Ratio Share".

1.4 Category B Load Ratio Share

Ratio of a Transmission Customer's Monthly Category B Load in the Designated State or Area for a Localized Facility to the Monthly Transmission System Category B Load for such Designated State or Area, calculated in accordance with Sections 16.5 and 16.6, and calculated on a rolling twelve month basis.

1.5 Designated Agent

See Tariff. Also, the Designated Agent of Eversource is Eversource Energy Service Company ("Eversource Service") which is a subsidiary of Eversource Energy.

1.6 Designated State or Area

The state or area to which the Commission allocates the costs of a Localized Facility identified in Section 16.3.

1.7 **Interest**

The amount computed in accordance with the Commission's regulations at 18 CFR §35.19a (a)(2)(iii). Interest on deposits and shall be calculated from the day the deposit check is credited to Eversource's account.

1.8 **Interruption**

A reduction in non-firm transmission service due to economic reasons pursuant to Schedule 21.

1.9 **Localized** Facility

Facility or costs that the New England System Operator determines should not be included in Attachment F of the ISO OATT.

1.10 **Network Load**

The load that a Network Customer designates for Local Network Service. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements for any Point-To-Point Transmission Service that may be necessary for such non-designated load.

1.11 **Network Operating Agreement**

An executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Local Network Service under Part III of this Local Service Schedule.

1.12 **Network Upgrades**

Modifications or additions to transmission-related facilities that are integrated with and support Eversource's overall Transmission System for the general benefit of all users of such Transmission System.

1.13 **New England System Operator**

ISO New England Inc. ("ISO") or its successor entity.

1.14 **Party(ies)**

Eversource and the Transmission Customer receiving service under the Tariff.

1.15 **Short-Term Firm Point-To-Point Transmission Service**

Firm Point-To-Point Transmission Service with a term of less than one year.

1.16 Service Agreement

Service Agreement is a transmission service agreement for transmission service provided under this Local Service Schedule or Localized Costs Responsibility Agreement ("LCRA").

1.17 **Service Year**

The calendar year in which the Transmission Customer is receiving service under this Local Service Schedule.

1.18 **Eversource**

The Connecticut Light and Power Company, Western Massachusetts Electric Company, and Public Service Company of New Hampshire, each an operating company of Eversource Energy, but excluding their affiliate NSTAR Electric Company, which provides Transmission Service pursuant to Schedule 21-NSTAR.

1.19 **Eversource's Monthly Transmission System Peak**

The maximum firm usage of the Eversource Transmission System in a calendar month (this does not include load of Eversource's customers exclusively connected to PTF).

1.20 **Eversource Transmission System**

The PTF and non-PTF facilities owned, controlled or operated by Eversource that are used to provide transmission service under this Local Service Schedule. This includes PTF facilities whose costs are not included in the regional rate.

1.21 **Transmission Service**

Point-To-Point Transmission Service provided under this Local Service Schedule on a firm and non-firm basis.

2. Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. Eversource is required to provide (or offer to arrange with the New England System Operator as discussed below), and the Transmission Customer is required to purchase, the following Ancillary Service (i) Scheduling, System Control and Dispatch.

The Transmission Customer serving load within the Eversource Control Area shall also obtain the following ancillary services: (i) Reactive Supply and Voltage Control from Generation Sources, (ii) Regulation and Frequency Response, (iii) Energy Imbalance, (iv) Operating Reserve - Spinning, and (v) Operating Reserve - Supplemental.

The Transmission Customer serving load within the Eversource Control Area is required to acquire the appropriate Ancillary Services, whether from the New England System Operator, Eversource, another party, or by self-supply.

The Transmission Customer may not decline Eversource's or the New England System Operator's offer of appropriate Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from Eversource.

If Eversource is unable to provide Scheduling, System Control and Dispatch, Eversource can fulfill its obligation to provide this Ancillary Service by acting as the Transmission Customer's agent to secure this Ancillary Service from the New England System Operator. The Transmission Customer may elect to (i) have Eversource act as its agent to obtain Scheduling, System Control and Dispatch, (ii) secure Scheduling, System Control and Dispatch directly from the New England System Operator, or from a third party.

Eversource or New England System Operator shall specify the rate treatment and all related terms and conditions in the event of an unauthorized use of Ancillary Services by the Transmission Customer.

The specific Ancillary Services, prices and/or compensation methods are described on the Schedule that is attached to and made a part of the Tariff. Three principal requirements apply to discounts for Ancillary Services provided by Eversource in conjunction with its provision of transmission service as follows: (1) any offer of a discount made by Eversource must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one’s wholesale merchant or an Affiliate’s use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. A discount agreed upon for an Ancillary Service must be offered for the same period to all Eligible Customers on the Eversource system.

3. Billing and Payment

3.1 **Billing Procedure**

Within a reasonable time after the first day of each month, Eversource Service shall submit an invoice to the Transmission Customer for the charges for all services furnished or costs allocated under the Tariff during the preceding month.

The invoice shall be paid by the Transmission Customer within twenty five (25) days of the date of the invoice. All payments shall be made in immediately available funds payable to Eversource Service, or by wire transfer to a bank named by Eversource Service. Billing hereunder shall be based on cost estimates made by Eversource subject to Annual True-up when actual costs for the Service Year are known. Such Annual True-up shall occur no later than six (6) months after the close of the Service Year to which the Annual True-up relates. The Annual True-up will include interest calculated in accordance with Section 35.19a of the Commission’s regulations. If the in

service date of a forecasted capital addition changes, and the impact of such change on Eversource's annual revenue requirement is ten percent or more, Eversource Service will adjust current billing to the Transmission Customer as appropriate.

3.2 Interest on Unpaid Balances

Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by Eversource Service.

3.3 Customer Default

In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to Eversource Service on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after Eversource Service notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, Eversource may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between Eversource and the Transmission Customer, Eversource will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then Eversource may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy. Neither Party shall have the right to challenge any monthly bill or to bring any court or administrative action of any kind questioning the propriety of any bill after a period of twenty four (24) months from the date the bill was due; provided, however, that in the case of a bill based on estimates, such twenty-four month period shall run from the due date of the final adjusted bill.

3.4 Transmission Customer Right to Audit

Eversource shall keep complete and accurate accounts and records with respect to its performance under this Local Service Schedule and shall maintain such data for a period of at least two (2)

years after final billing for audit by a Transmission Customer. The Transmission Customer shall provide thirty (30) days' written notice to Eversource to request an audit of all such accounts and records relevant to service provided to the Transmission Customer for a specific time period. The Transmission Customer shall have the right, during normal business hours and at its own expense, to examine, inspect and make copies of all such accounts and records relevant to service provided to the Transmission Customer at such offices where such accounts and records are maintained, insofar as may be necessary for the purpose of ascertaining the reasonableness and accuracy of all relevant data, estimates or statements of charges submitted hereunder to the Transmission Customer. The records made available to a Transmission Customer for auditing purposes hereunder shall not include information pertaining to the loads of or charges to an individual customer other than the Transmission Customer; unless the Transmission Customer requests that the Commission order that such information be made available to the Transmission Customer and the Commission so orders. Nothing in this section shall be interpreted as limiting the Transmission Customer's access to system-wide load or charge data.

3.5 Regulatory Oversight of Formula Rate

Eversource will submit to the Connecticut Public Utilities Regulatory Authority, the Massachusetts Department of Public Utilities and the New Hampshire Public Utilities Commission ("State Commissions") the following information:

(a) A copy of the New England Power Pool's ("NEPOOL's") or any successor's annual informational filing at FERC supporting the total transmission revenue requirement for New England, which contains information submitted by Eversource supporting its total transmission revenue requirement;

(b) Eversource's total transmission revenue requirement as calculated in Attachments H & I under Schedule 21-ES;

(c) A copy of Eversource's applications under Restated NEPOOL Agreement Section 15.5, concerning the installation of or material changes to transmission facilities (or any successor approval process), and Section 18.4, concerning plans for additions, retirements, or changes in the capacity of transmission facilities (including descriptions of facilities and cost estimates);

(d) A copy of ISO New England's or any successor's Regional Transmission System Plan, which contains all identified improvements to the New England power system approved by the ISO New England or any successor's board;

(e) A copy of Eversource's filing to each New England state's siting council for those projects to be recovered through the RNS or LNS rates, such copy to be filed with the State Commissions when the estimated costs of the projects in question are proposed to be included in the RNS and LNS rates;

(f) At the same time that new estimated rates are implemented, the estimated cost for each capital addition (on a project-by-project basis) the cost of which is to be included in the estimated rates; and, for each such capital addition with an estimated cost of $20 million or greater, Eversource will provide the following to the extent available: (i) a breakdown of the projected cost into the following categories: labor (broken down into planning, engineering, construction, and other), outside services (broken down into planning, engineering, construction and other), materials (broken down into station equipment, towers and poles, overhead conductor, underground conduit and conductor, and other), land (broken down into fee ownership, easement, and other), and other (if applicable) and (ii) a non-binding estimate of the total project costs by calendar quarter;

(g) Within 60 days after the true-up is rendered for a year, the actual cost for each capital addition that was placed in service during that year; and, for each such capital addition with an actual or estimated cost of $20 million or greater, Eversource will provide the following to the extent available: (i) a breakdown of the actual cost into the following categories: labor (broken down into planning, engineering, construction, and other), outside services (broken down into planning, engineering, construction, and other), materials (broken down into station equipment, towers and poles, overhead conductor, underground conduit and conductor, and other), land (broken down into fee ownership, easement, and other), and other (if applicable) and (ii) the actual total project costs by calendar quarter.

4. Regulatory Filings

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the right of Eversource to unilaterally make application to the Commission for a change in rates, terms and

conditions, charges, classification of service, Service Agreement, rule or regulation under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the ability of any Party receiving service under the Tariff to exercise its rights under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

5. Creditworthiness: See Attachment ES-L to this Schedule 21-ES.

6. Rights Under The Federal Power Act

Nothing in this section shall restrict the rights of any party to file a complaint with the Commission under relevant provisions of the Federal Power Act.

II. POINT-TO-POINT TRANSMISSION SERVICE

Scheduling of Point-To-Point Transmission Service:

The System Operator will dispatch all resources subject to its control, pursuant to Market Rule 1, in order to meet load and to accommodate external transactions. Resources within the New England Control Area using Firm Point-to-Point Transmission Service shall be dispatched based on economic merit in accordance with Market Rule 1 and will have no physical scheduling or dispatch rights. Transmission Customers will be charged for congestion costs and any other costs associated with such dispatch in accordance with Market Rule 1.

7. Nature of Firm Point-To-Point Transmission Service

7.1 Classification of Firm Transmission Service

The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedule ES-2, as appropriate, for Long and Short-Term Firm Point-To-Point Transmission Service. In the event that either a Transmission Customer has not made a capacity reservation, or a Transmission Customer exceeds its firm capacity reservation at the Point of Receipt and Point of Delivery the Transmission Customer shall be billed and pay for its actual use of such excess capacity in addition to any Reserved Capacity pursuant to Schedule ES-2, including ancillary services provided pursuant to Schedule ES-1 hereto.

8. Nature of Non-Firm Point-To-Point Transmission Service

8.1 Classification of Non-Firm Point-To-Point Transmission Service

The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedule ES-3, as appropriate, for non-firm Point-To-Point Transmission Service. In the event that either a Transmission Customer has not made a capacity reservation, or a Transmission Customer exceeds its non-firm capacity reservation at any Point of Receipt or Point of Delivery, the Transmission Customer shall be billed and pay for its actual use of such excess capacity in addition to any Reserved Capacity pursuant to Schedule ES-3, including ancillary services provided pursuant to Schedule ES-1 hereto. Non-Firm Point-To-Point Transmission Service shall include transmission of energy on an hourly basis and transmission of scheduled short-term capacity and/or energy on a daily, weekly or monthly basis, but not to exceed one month's reservation for any one Application, under Schedule ES-3.

9. Service Availability

9.1 Real Power Losses

Real Power Losses are associated with all transmission service. Eversource is not obligated to provide Real Power Losses. The Transmission Customer is responsible for replacing losses associated with all transmission service as determined under Market Rule 1. The applicable Real Power Loss factors are as follows:

The amount of transmission losses incurred in transmitting power from the POR(s) to the POD(s) ("Loss Amount") shall be determined from time to time by the New England System Operator in accordance with ISO procedures applicable at the time of delivery. The Loss Amounts, when determined by the New England System Operator, shall be posted on Eversource's Open Access Same-Time Information System ("OASIS"). In the event that the New England System Operator, for any reason, does not determine the entire Loss Amount, the losses not determined by the New England System Operator shall be based on average system losses as set forth below:

Cumulative Losses in Percent

POR/POD	Peak*	Off-Peak	24 Hr. Avg.
Bulk Transmission	1.98	2.42	2.21
Bulk Substation	2.46	2.92	2.70
Pri. Distribution	4.58	4.50	4.54

*Peak hours are defined as 0700-2300, Monday-Friday; Off-Peak hours are all other hours.

10. Procedures for Arranging Firm Point-To-Point Transmission Service

10.1 Deposit

A Completed Application for Firm Point-To-Point Transmission Service also shall include a deposit of either three month's charge for Reserved Capacity or the full charge for Reserved Capacity for service requests of less than one month.

11. Additional Study Procedures For Firm Point-To-Point Transmission Service Requests:

11.1 Disbursement Methodology for Late Study Penalties

See Attachment ES-D to Schedule 21-ES.

12. Compensation for Transmission Service

The Transmission Customers taking Point-To-Point Transmission Service shall pay Eversource for any Direct Assignment Facilities, Ancillary Services and applicable study costs, along with the following:

12.1 Rates and Charges for Transmission Service

Rates for Firm and Non-Firm Point-To-Point Transmission Services are provided in the Attachments appended to this Local Service Schedule: Firm Point-To-Point Transmission Services (Schedule ES-2); and Non-Firm Point-To-Point Transmission Services (Schedule ES-3).

12.2 Rates for Firm and Non-Firm Point-To-Point Transmission Services

Rates for Firm and Non-Firm Point to Point Transmission Services shall be determined as set forth in Attachments ES-2 and ES-3 of this Local Service Schedule on the basis of estimated

costs for each Service Year until the actual costs for such Service Year are determined. Thereafter, payments made on such estimated costs shall be recalculated based on actual data for that Service Year, and an appropriate billing adjustment shall be made pursuant to Section 3 of this Local Service Schedule. Eversource shall use Part II of the Tariff to make its Third-Party Sales. Eversource shall account for such use at the applicable Tariff rates.

III. LOCAL NETWORK SERVICE

13. Nature of Local Network Service

13.1 Real Power Losses

Real Power Losses are associated with all transmission service. Eversource is not obligated to provide Real Power Losses. The Network Customer is responsible for replacing losses associated with all transmission service as determined under Market Rule 1. The applicable Real Power Loss factors are as follows:

The amount of transmission losses incurred in transmitting power across the Eversource Transmission System to the Network Customer's Network Load shall be determined from time to time by the New England System Operator in accordance with ISO procedures applicable at the time of delivery. The Loss Amounts, when determined by the New England System Operator, shall be posted on the Open Access Same-Time Information System ("OASIS"). In the event that the New England System Operator, for any reason, does not determine the entire Loss Amount, the losses not determined by the New England System Operator shall be based on average system losses as set forth below:

Cumulative Losses in Percent

POR/POD	Peak*	Off-Peak	24 Hr. Avg.
Bulk Transmission	1.98	2.42	2.21
Bulk Substation	2.46	2.92	2.70
Pri. Distribution	4.58	4.50	4.54

*Peak hours are defined as 0700-2300, Monday-Friday; Off-Peak hours are all other hours.

14. Network Resources

14.1 Use of Interface Capacity by the Network Customer

There is no limitation upon a Network Customer's use of the Eversource Transmission System at any particular interface to integrate the Network Customer's Network Resources (or substitute economy purchases) with its Network Loads. However, a Network Customer's use of Eversource's total interface capacity with other transmission systems may not exceed the Network Customer's Load.

15. Additional Study Procedures For Local Network Service Requests

15.1 Disbursement Methodology for Late Study Penalties See Attachment ES-D to Schedule 21-ES

16. Rates and Charges

The Network Customer shall pay Eversource for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following:

16.1 Rates and Charges

Rates for Local Network Service shall be determined as set forth in Schedule ES-4 on the basis of estimated costs for each Service Year until the actual costs for such Service Year are determined. Thereafter, payments made on such estimated costs shall be recalculated based on actual data for that Service Year, and an appropriate billing adjustment shall be made pursuant to Section 3 of this Local Service Schedule.

16.2 Eligible Customers Taking Service Under the ISO Tariff

Any Eligible Customer taking Regional Network Service under the ISO Tariff in a Designated State or Area shall pay to Eversource Service the customer's Category B Load Ratio Share of the Formula Requirements as calculated in Schedule ES-4, Appendix B for such Designated State or Area**.** Eversource Service shall execute a LCRA under this Local Service Schedule, in the form set forth in Attachment ES-E, to recover such charges from such customer. Eversource Service shall not bill any such customer any such costs until (1) such LCRA has been executed with the

Eligible Customer, or (2) an unexecuted LCRA has been permitted to be made effective **by** the Commission.

16.3 Listing of Localized Facilities by Designated State or Area:

(a) Connecticut:
Bethel to Norwalk Project
Middletown to Norwalk Project
Glenbrook Cables Project
Greater Springfield Reliability Project (Connecticut portion)

(b) Massachusetts:
Greater Springfield Reliability Project (Massachusetts portion)

16.4 **Monthly Demand Charge**

The Network Customer shall pay monthly Demand Charges, which shall be determined by multiplying its Category A Load Ratio Share times one twelfth (1/12) of the Formula Requirements in Schedule ES-4, Appendix A, and by multiplying its Category B Load Ratio Share for the Designated State or Area times one twelfth (1/12) of the Formula Requirements in Schedule ES-4, Appendix B for the Localized Facilities that are in such Designated State or Area.

16.5 **Determination of Network Customer's Monthly Network Load**

The Network Customer's Monthly Category A Network Load is its hourly load (including its designated Network Load not physically interconnected with Eversource under Schedule 21) coincident with Eversource's Monthly Transmission System Peak.

The Network Customer's Monthly Category B Load for a Designated State **or** Area for a Localized Facility is its hourly load in such Designated State or Area coincident with the monthly transmission system peak load for such Designated State or Area.

For Localized Facilities for which the Designated State or Area is identified as "Connecticut" in Section 16.3(a) of this Schedule 21-ES, the customer's hourly load shall be all of the customer's

Regional Network Load in Connecticut, and the monthly transmission system peak load shall be all Regional Network Load in Connecticut.

For Localized Facilities for which the Designated State or Area is identified as “Massachusetts” in Section 16.3(b) of this Schedule 21-ES, the customer’s hourly load shall be all of the customer’s Regional Network Load in Massachusetts, and the monthly transmission system peak load shall be all Regional Network Load in Massachusetts; provided, that the customer’s monthly load and the monthly transmission system peak load shall exclude the load of generators taking RNS for the delivery of offline station service.

16.6 **Determination of Eversource’s Monthly Transmission System Load**

Eversource’s Monthly Transmission System Category A Load is Eversource’s Monthly Transmission System Peak minus the coincident peak usage of all Firm Point-To-Point Transmission Service customers pursuant to this Local Service Schedule plus the Reserved Capacity of all Firm Point-To-Point Transmission Service customers.[1]

Eversource’s Monthly Transmission System Category B Load for the Designated State or Area for a **Localized** Facility is the monthly transmission system peak load for such Designated State or Area.[1]

For Localized Facilities for which the Designated State or Area is identified as “Connecticut” in Section 16.3(a) of this Schedule 21-ES, the monthly transmission system peak load shall be all Regional Network Load in Connecticut.

For Localized Facilities for which the Designated State or Area is identified as “Massachusetts” in Section 16.3(b) of this Schedule 21-ES, the monthly transmission system peak load shall be all Regional Network Load in Massachusetts; provided, that the monthly transmission system peak load shall exclude the load of generators taking RNS for the delivery of offline station service.

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[1] Excludes MWs associated with lump sum payment transactions identified in footnote 2.

17. Operating Arrangements

17.1 Operation under the Network Operating Agreement

The Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Network Operating Agreement.

17.2 Network Operating Agreement

The terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Part III of the Tariff shall be specified in the Network Operating Agreement. The Network Operating Agreement shall provide for the Parties to (i) operate and maintain equipment necessary for integrating the Network Customer within the Eversource Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between Eversource and the Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside the Eversource Transmission System, interchange schedules, unit outputs for redispatch, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted loads and resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of Part III of the Tariff, including scheduling protocols. The Network Operating Agreement will recognize that the Network Customer shall either (i) operate as a Control Area under applicable guidelines of the North American Electric Reliability Council (NERC) and the Northeast Power Coordinating Council (NPCC), (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with Eversource, or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies NERC and NPCC requirements. Eversource shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services. The Network Operating Agreement is included in Attachment ES-G.

SCHEDULE ES-1

SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by Eversource (if Eversource is the Control Area operator) or indirectly by Eversource making arrangements with the New England System Operator that performs this service for the Eversource Transmission System. The Transmission Customer must purchase this service from Eversource or the New England System Operator. The charges for Scheduling, System Control and Dispatch Service are to be based on the rates set forth below. To the extent the New England System Operator performs this service for Eversource, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to Eversource by that New England System Operator.

Each Point-To-Point Transmission Customer under this Local Service Schedule will be charged for Transmission Scheduling, System Control and Dispatch Services for the total Reserved Capacity specified in each reservation for Point-To-Point Transmission Service made under this Local Service Schedule at the rates set forth in Appendix A of this Schedule ES-1. In the event that a Transmission Customer utilizes transmission capacity without a reservation or exceeds its capacity reservation at any Point of Receipt or Point of Delivery, the Transmission Customer **shall** pay for its actual use of such excess capacity in addition to any Reserved Capacity. The charge for such excess use of capacity shall be determined by multiplying the sum of the actual use in excess of its capacity reservation times the hourly non-firm rate posted on Eversource's OASIS including ancillary services provided pursuant to Schedule ES-1 hereto.

Each Network Customer under this Local Service Schedule will be charged a monthly Transmission Scheduling, System Control and Dispatch Service Demand Charge, which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of the Formula Requirements specified in Appendix B of this Schedule ES-1.

Each Transmission Customer with generation within the New England Control Area shall be required also to provide for Scheduling, System Control and Dispatch Service for that generation. It is anticipated that the Transmission Customer will obtain these services from the ISO. Eversource will make available

Generation Scheduling, System Control and Dispatch Service at the rates set forth in Appendix C of this Schedule ES-1.

Each Transmission Customer with generation located outside of the New England Control Area shall be required to provide for Scheduling, System Control and Dispatching Service for that generation. It is anticipated that the Transmission Customer will obtain these services by contracting for these services from the provider of these services within the Control Area where the generation is located.

Eversource shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Schedule ES-1 in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE ES-1

Appendix A

POINT-TO-POINT TRANSMISSION RATE

Eversource’s Formula Rate for Point-To-Point Transmission Scheduling, System Control and Dispatch Service ("Formula Rate") is an annual rate determined from the following formula.

Formula Rate$_i$ = $(A_{i-1} - B_{i-1})\, C_{i-1}$ *WHERE:*

- i equals the calendar year during which service is being rendered ("Service Year").

- A_{i-1} is the Annual Control Center Expenses (expressed in dollars) of Eversource for the calendar year prior to the Service Year. The Annual Control Center Expenses are determined pursuant to the formula specified in Exhibit 1 to this Appendix A of Schedule ES-1.

- B_{i-1} is the actual transmission scheduling, system control and dispatch revenues (expressed in dollars) provided from the provision of transmission services to others. The actual transmission scheduling and dispatch revenues shall be those recorded on the books of each of the companies comprising Eversource hereunder in FERC Account No. 456.1 pertaining to Transmission of Electricity for Others and such other applicable FERC accounts for the calendar year prior to the Service Year.

- C_{i-1} is the average Eversource Monthly Transmission System Category A Load (expressed in kilowatts).

SCHEDULE ES-1

Appendix A

Exhibit 1

DETERMINATION OF ANNUAL CONTROL CENTER EXPENSES

The rate formula for determination of the annual control center expenses revenue requirements for each of the companies comprising Eversource hereunder is determined as follows:

A. ANNUAL CONTROL CENTER EXPENSES

Eversource's System Control and Load Dispatching Expense, for the calendar year prior to the Service Year, as recorded in FERC Account 561.1-561.4 and the revenue requirement calculation for the CL&P Dispatch Center Plant as described in Appendix A, Exhibit 2.

SCHEDULE ES-1

APPENDIX A

EXHIBIT 2

CL&P DISPATCH CENTER REVENUE REQUIREMENT

This exhibit calculates the CL&P Dispatch Center Revenue Requirement. The CL&P Dispatch Center Revenue Requirement for use during a calendar year shall be based on CL&P's costs for the immediately preceding calendar year.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section I. of the ISO-NE Transmission, Markets and Services Tariff and as used in this exhibit have the following definitions:

<u>Dispatch Center</u> means CL&P's CONVEX dispatch center.

<u>Dispatch Center Plant</u> shall equal CL&P's year-end gross plant balances used for CL&P's Dispatch Center as recorded in FERC Account Nos. 303, 350-359, and 389-399.

<u>Dispatch Center Depreciation Reserve</u> shall equal CL&P's year-end depreciation reserve balance for Dispatch Center Plant as recorded in FERC Account No. 108.

<u>Dispatch Center Accumulated Deferred Income Taxes</u> shall equal the net of CL&P's year-end deferred tax balances for Dispatch Center Plant as recorded in FERC Account Nos. 281-283 and 190.

II. CALCULATION OF TOTAL DISPATCH CENTER REVENUE REQUIREMENT

The Dispatch Center Revenue Requirement shall equal the sum of (A) Dispatch Center Return and Associated Income Taxes, (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Amortization of Investment Tax Credits, and (D) Dispatch Center Municipal Tax Expense; provided, that during the period January 1, 2008 through December 31, 2008, the Dispatch Center Revenue Requirement shall equal the product of (i) the number of months (or fractions thereof) remaining in 2007 on and after the date upon which the CONVEX Agreements are permitted to be made effective by FERC, divided by 12 and (ii) the sum of (A) Dispatch Center Return and Associated Income Taxes, (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Amortization of Investment Tax Credits, and (D) Dispatch Center Municipal Tax Expense. "CONVEX Agreements" refers to the agreements between The

Connecticut Light & Power Company and various entities relating to the operation of the Dispatch Center and filed with FERC contemporaneously with the filing of this Exhibit 2.

A. Dispatch Center Return and Associated Income Taxes shall equal the product of the Dispatch Center Investment Base and the Cost of Capital Rate.

1. Dispatch Center Investment Base

The Dispatch Center Investment Base will be the year-end balances of: (a) Dispatch Center Plant, less (b) Dispatch Center Depreciation Reserve, less (c) Dispatch Center Accumulated Deferred Income Taxes.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) the Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon CL&P's capital structure at the end of each year and will equal the sum of (i),(ii), and (iii) below.

(i) The long-term debt component, which equals the product of the year-end balance of CL&P's first mortgage bonds and pollution control notes adjusted for premiums, discounts, debt expense and losses on reacquired debt and the ratio of the long term debt to CL&P's total capital.

(ii) The preferred stock component, which equals the product of the year-end balance of CL&P's preferred stock adjusted for premiums, discounts and unamortized issue expense and the ratio of the preferred stock to CL&P's total capital.

(iii) The common equity component, which equals the product of 10.3% and the ratio of the common equity to CL&P's total capital.

(b and c) Federal and State Income Taxes shall be computed as follows:

A x B x C

where:

A = Dispatch Center Investment Base

B = Cost of equity capital (the sum of the preferred stock component and common equity component)

C = TE / (1-TE), where TE is the effective combined federal and state statutory income tax rates in effect at the applicable time.

B. Dispatch Center Depreciation Expense shall equal CL&P's Dispatch Center depreciation expense as recorded in FERC Account No. 403.

C. Dispatch Center Amortization of Investment Tax Credits shall equal CL&P's Dispatch Center amortization of investment tax credits as recorded in FERC Account No. 411.4.

D. Dispatch Center Municipal Tax Expense shall equal CL&P's Dispatch Center municipal tax expense as recorded in FERC Account Nos. 408.1 and 409.1.

SCHEDULE ES-1

Appendix B

NETWORK TRANSMISSION FORMULA REQUIREMENTS

Eversource's formula requirements for Network Transmission Scheduling, System Control and Dispatch Service is determined from the following formula.

Formula $\text{Requirements}_i = (A_{i\text{-}1} - B_{i\text{-}1})$

WHERE:

- i equals the calendar year during which service is being rendered ("Service Year").

- $A_{i\text{-}1}$ is the Annual Control Center Expenses (expressed in dollars) of Eversource for the calendar year prior to the Service Year. The Annual Control Center Expenses are determined pursuant to the formula specified in Exhibit 1 to this Appendix B of Schedule ES-1.

- $B_{i\text{-}1}$ is the actual transmission scheduling, system control and dispatch revenues (expressed in dollars) provided from the provision of transmission services to others. The actual transmission scheduling, system control and dispatch revenues shall be those recorded on the books of each of the companies comprising Eversource hereunder in FERC Account No. 456.1 pertaining to Transmission of Electricity for Others and such other applicable FERC Account for the calendar year prior to the Service Year.

SCHEDULE ES-1

APPENDIX B

EXHIBIT 1

DETERMINATION OF ANNUAL CONTROL CENTER EXPENSES

The rate formula for determination of the annual control center expenses for each of the companies comprising Eversource hereunder is determined as follows:

A. <u>ANNUAL CONTROL CENTER EXPENSES</u>

Eversource's System Control and Load Dispatching Expense), for the calendar year prior to the Service Year as recorded in FERC Account 561.1-561.4 and the revenue requirement calculation for the CL&P Dispatch Center Plant as described in Appendix B, Exhibit 2.

SCHEDULE ES-1

APPENDIX B

EXHIBIT 2

CL&P DISPATCH CENTER REVENUE REQUIREMENT

This exhibit calculates the CL&P Dispatch Center Revenue Requirement. The CL&P Dispatch Center Revenue Requirement for use during a calendar year shall be based on CL&P's costs for the immediately preceding calendar year.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section I. of the ISO-NE Transmission, Markets and Services Tariff and as used in this exhibit have the following definitions:

Dispatch Center means CL&P's CONVEX dispatch center.

Dispatch Center Plant shall equal CL&P's year-end gross plant balances used for CL&P's Dispatch Center as recorded in FERC Account Nos. 303, 350-359, and 389-399.

Dispatch Center Depreciation Reserve shall equal CL&P's year-end depreciation reserve balance for Dispatch Center Plant as recorded in FERC Account No. 108.

Dispatch Center Accumulated Deferred Income Taxes shall equal the net of CL&P's year-end deferred tax balances for Dispatch Center Plant as recorded in FERC Account Nos. 281-283 and 190.

II. CALCULATION OF TOTAL DISPATCH CENTER REVENUE REQUIREMENT

The Dispatch Center Revenue Requirement shall equal the sum of (A) Dispatch Center Return and Associated Income Taxes, (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Amortization of Investment Tax Credits, and (D) Dispatch Center Municipal Tax Expense; provided, that during the period January 1, 2008 through December 31, 2008, the Dispatch Center Revenue Requirement shall equal the product of (i) the number of months (or fractions thereof) remaining in 2007 on and after the date upon which the CONVEX Agreements are permitted to be made effective by FERC, divided by 12 and (ii) the sum of (A) Dispatch Center Return and Associated Income Taxes, (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Amortization of Investment Tax Credits, and (D) Dispatch Center Municipal Tax Expense. "CONVEX Agreements" refers to the agreements between The

Connecticut Light & Power Company and various entities relating to the operation of the Dispatch Center and filed with FERC contemporaneously with the filing of this Exhibit 2.

A. <u>Dispatch Center Return and Associated Income Taxes</u> shall equal the product of the Dispatch Center Investment Base and the Cost of Capital Rate.

1. Dispatch Center Investment Base

<u>The Dispatch Center Investment Base</u> will be the year-end balances of: (a) Dispatch Center Plant, less (b) Dispatch Center Depreciation Reserve, less (c) Dispatch Center Accumulated Deferred Income Taxes.

2. Cost of Capital Rate

<u>The Cost of Capital Rate</u> will equal (a) the Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon CL&P's capital structure at the end of each year and will equal the sum of (i),(ii), and (iii) below.

(i) The long-term debt component, which equals the product of the year-end balance of CL&P's first mortgage bonds and pollution control notes adjusted for premiums, discounts, debt expense and losses on reacquired debt and the ratio of the long term debt to CL&P's total capital.

(ii) The preferred stock component, which equals the product of the year-end balance of CL&P's preferred stock adjusted for premiums, discounts and unamortized issue expense and the ratio of the preferred stock to CL&P's total capital.

(iii) The common equity component, which equals the product of 10.3% and the ratio of the common equity to CL&P's total capital.

(b and c) Federal and State Income Taxes shall be computed as follows:

A x B x C

where:

A = Dispatch Center Investment Base

B = Cost of equity capital (the sum of the preferred stock component and common equity component)

C = TE / (1-TE), where TE is the effective combined federal and state statutory income tax rates in effect at the applicable time.

B. Dispatch Center Depreciation Expense shall equal CL&P's Dispatch Center depreciation expense as recorded in FERC Account No. 403.

C. Dispatch Center Amortization of Investment Tax Credits shall equal CL&P's Dispatch Center amortization of investment tax credits as recorded in FERC Account No. 411.4.

D. Dispatch Center Municipal Tax Expense shall equal CL&P's Dispatch Center municipal tax expense as recorded in FERC Account Nos. 408.1 and 409.1.

SCHEDULE ES-1

Appendix C

GENERATION RATES

Eversource's Formula Rate for Generation Scheduling, System Control and Dispatch Service ("Formula Rate") shall be calculated using the Point-to-Point Formula Rate for Transmission Scheduling, System Control, and Dispatch Service in Appendix A of Schedule ES-1.

SCHEDULE ES-2

FIRM POINT-TO-POINT SERVICE

I. Each month, Eversource Service shall bill the Transmission Customer for Long-Term Firm and Short-Term Firm Transmission Service and the Transmission Customer shall be obligated to pay Eversource the charges as set forth in this Schedule ES-2, as applicable.

A. <u>TRANSMISSION CHARGES</u>

1. <u>Determination of Transmission Charges</u>

The Transmission Charges will provide for recovery of the costs of the transmission facilities ofEversource. The Category A Transmission Charges for each month will equal the sum of the Category A Charges for each monthly (or longer term), weekly or daily transaction during such month. In the event that a Transmission Customer utilizes transmission capacity without a reservation or exceeds its capacity reservation at any Point of Receipt or Point of Delivery, the Transmission Customer **shall** pay for its actual use of such excess capacity in addition to the charges for each monthly, weekly or daily transactions during such month. The charge for such excess use of capacity shall be determined by multiplying the actual hourly use in excess of its capacity reservation times the applicable Category A on-peak or off-peak hourly non-firm rate posted on Eversource's OASIS pursuant to Schedule ES-3 including ancillary services provided pursuant to Schedule ES-1 hereto.

The Category A Charge for each monthly (or longer term) transactions will be the product of: (a) Eversource's Category A Formula Rate (expressed in $ per kilowatt-year), divided by twelve (12) months, and (b) the Reserved Capacity set forth for such monthly (or longer term) transaction (expressed in kilowatts).

The Category A Charge for each weekly transaction will be the product of: (a) Eversource's Weekly Category A Short-Term Firm Point-To-Point Transmission Rate (expressed in $ per kilowatt-week), and (b) the Reserved Capacity set forth for such weekly transaction (expressed in kilowatts). Eversource's Weekly Category A Rate is Eversource's Category A Formula Rate for Firm Point-To-Point Transmission Service divided by fifty-two (52) weeks.

The Category A Charge for each daily transaction will be the product of: (a) Eversource's Daily Category A Short-Term Firm Point-To-Point Transmission Rate (expressed in $ per kilowatt-day), and (b) the Reserved Capacity set forth for such daily transaction (expressed in kilowatts). Eversource's Daily Category A Rate is Eversource's Weekly Category A Rate for Short-Term Firm Point-To-Point Transmission Service divided by five (5) days. The total of the Transmission Customer's charges for daily transactions, under an individual reservation, in a seven (7) day period shall not exceed the charges based on the Weekly Category A Rate and the Transmission Customer's maximum Reserved Capacity in the period.

2. Eversource's Formula Rates

Eversource's Formula Rates for Long-Term Firm and Short-Term Firm Point-To-Point Service shall be determined in accordance with the rate formulas specified in Appendix A of this Schedule ES-2.

3. Tax Rates and Taxes

Eversource's Formula Rates set forth in this schedule in effect during a Service Year shall be based on the local, state, and federal tax rates and taxes in effect during the Service Year. If, at any time, additional or new taxes are imposed on Eversource or existing taxes are removed, Eversource's Formula Rate will be appropriately modified and filed with the Commission in accordance with Part 35 of the Commission's regulations.

4. Provision re: Exchanges

With respect to Entitlement Transactions or Energy Transactions or other transactions that involve an exchange, each party to such transaction shall be treated as an individual Transmission Customer under this Local Service Schedule. Accordingly, a separate Schedule ES-2 or other

applicable charge(s) will be calculated for, and a separate bill will be rendered to, each such individual Transmission Customer.

5. Discounts

Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by Eversource must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, Eversource must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

6. Resales

The rates and rules governing charges and discounts in Sections I.A.1 and 5 of this Schedule ES-2 stated above shall not apply to resales of transmission service, compensation for which shall be governed by Schedule 21.

II. In addition to the applicable charges of this Local Service Schedule, and as otherwise specified in the Service Agreement, the Transmission Customer shall pay to Eversource Service each month the following additional charges for Long-Term, and Short-Term Firm Point-To-Point Transmission Service provided during such month.

A. Taxes and Fees Charge

B. Regulatory Expenses Charge

C. Other

A. **TAXES AND FEES CHARGE**

If any governmental authority requires the payment of any fee or assessment or imposes any form of tax with respect to payments made for Long-Term Firm or Short Term Firm Point-To-Point Transmission Service provided under this Local Service Schedule, not specifically provided for in any of the charge or

rate provisions under this Local Service Schedule, including any applicable interest charged on any deficiency assessment made by the taxing authority, together with any further tax on such payments, the obligation to make payment for any such fee, assessment, or tax shall be borne by the Transmission Customer. Eversource will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's regulations.

B. **REGULATORY EXPENSES CHARGE**

Eversource shall have the right to make a Section 205 filing for recovery of regulatory expenses associated with this Local Service Schedule and the Service Agreements.

C. **OTHER**

Eversource shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Schedule ES-2 in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE ES-2

Appendix A

CATEGORY A RATE

FIRM POINT-TO-POINT TRANSMISSION SERVICE

Eversource’s Category A Formula Rate for Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service ("Formula Rate") is an annual rate determined from the following formula.
Formula $Rate_i = (A_i - B_i + C_i - D_i) / E_i$

WHERE:

- i equals the Service Year.

- A is the annual Total Transmission Revenue Requirements (expressed in dollars) as described in Attachment ES-H,

- B is the revenues received (expressed in dollars) from the provision of transmission and other related services, to others as recorded in FERC Accounts 456.1 and 454 to the extent that such transactions are not included in the determination of load (E),[2] minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

- C is the transmission payments (expressed in dollars) to the New England System Operator as recorded in FERC Account 565 in accordance with the Tariff.

- D is the sum of the annual revenues received (expressed in dollars) for the costs associated with the Localized Facilities, minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

- E is the average Eversource Monthly Transmission System Category A Load (expressed in kilowatts).

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[2] Includes amortization of revenues from point-to-point transmission service provided to Consolidated Edison Energy Massachusetts, Inc. and NRG Energy, Inc. under contracts in which customers paid based on single lump sum payment.

SCHEDULE ES-2

[Reserved]

SCHEDULE ES-3

NON-FIRM POINT-TO-POINT SERVICE

I. Eversource shall bill the Transmission Customer for Non-Firm Point-To-Point Transmission Service, and the Transmission Customer shall be obligated to pay Eversource the charges as set forth in this Schedule ES-3 as applicable.

A. **TRANSMISSION CHARGES**

1. General

The Transmission Customer shall pay to Eversource Service each month the Category A Transmission Charges calculated for all of the Transmission Customer's monthly transactions, weekly transactions, daily transactions and hourly transactions, each as set forth below. In the event that a Transmission Customer utilizes transmission capacity without a reservation or exceeds its capacity reservation at any Point of Receipt or Point of Delivery, the Transmission Customer shall pay for its actual use of such excess capacity in addition to the charges for each monthly, weekly, daily or hourly transactions during such month. The charge for such excess use of capacity shall be determined by multiplying the actual hourly use in excess of its capacity reservation times the applicable Category A on-peak or off-peak hourly non-firm rate posted on Eversource's OASIS pursuant to this Schedule ES-3 including ancillary services provided pursuant to Schedule ES-1 hereto.

With respect to any wholesale transactions that involve an exchange, each party to such transaction shall be an individual Transmission Customer under this Local Service Schedule. Accordingly, a Transmission Charge, as applicable, will be calculated for, and a separate bill will be rendered to, each such Transmission Customer.

The Category A Transmission Charge for each month applicable to a monthly transaction shall be determined as the product of: (a) the Category A rate posted on Eversource's Open Access Same-Time Information System ("OASIS") at the time the service is reserved, not to exceed Eversource's Annual Category A Rate for Non Firm Point-To-Point Transmission Service divided by twelve (12) months and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Reservation for such month (expressed in kilowatts).

The Category A Transmission Charge for each month applicable to weekly transactions shall be the sum of the transmission charges determined for each weekly transaction during such month. The transmission charge for each weekly transaction shall be determined as the product of: (a) the Category A rate posted on Eversource's OASIS at the time the service is reserved, not to exceed Eversource's Weekly Category A Firm Point-To-Point Transmission Charge Rate (expressed in $ per kilowatt-week), and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Reservation for such week (expressed in kilowatts). Eversource's Weekly Category A Rate is Eversource's Annual Category A Rate for Non-Firm Point-To-Point Transmission Service divided by fifty-two (52) weeks.

The Transmission Charge for each month applicable to daily transactions will be the sum of the transmission charges determined for each daily transaction. The transmission charge for each daily transaction shall be determined as the product of: (a) the rate posted on Eversource's OASIS at the time the service is reserved, not to exceed Eversource's Daily Category A Firm Point-To-Point Transmission Charge Rate (expressed in $ per kilowatt-day), and (b) the Reserved Capacity set forth in the Transmission Customer's applicable Reservation for such day (expressed in kilowatts). Eversource's Daily Category A On-Peak Rate is Eversource's Weekly Category A Rate for Non-Firm Point-To-Point Transmission Service divided by five (5) days. Eversource's Daily Category A Off-Peak Rate is Eversource's Weekly Category A Rate for Non-Firm Point-To-Point Transmission Service divided by seven (7) days. The total of the Transmission Customer's charges for daily transactions, under an individual Reservation, in a seven (7) day period shall not exceed the charges based on the Weekly Category A Rate and the Transmission Customer's maximum Reserved Capacity in the period.

The Transmission Charge for each month applicable to hourly transactions will be the sum of the transmission charges determined for each hourly transaction during such month. The transmission charge for each hour of an hourly Transaction shall be determined as the product of: (a) the rate posted on Eversource's OASIS at the time the service is reserved, not to exceed Eversource's Daily Category A Firm Point-To-Point Transmission Service Rate divided by sixteen (16) hours (expressed in $ per kilowatt-hour), and (b) the Reserved Capacity as set forth in the Transmission Customer's applicable Reservation for such hour (expressed in kilowatts). Eversource's Hourly Category A On-Peak Rate is equal to Eversource's Daily Category A Rate for Non-Firm Transmission Service divided by sixteen (16) hours. Eversource's Hourly Category A Off-Peak Rate is equal to Eversource's Daily Category A Rate for Non-Firm Transmission

Service divided by twenty-four (24) hours. The total of the Transmission Customer's charges for hourly transactions, under an individual Reservation, in a twenty-four (24) hour period shall not exceed the charges based on the Daily Category A Rate and the Transmission Customer's maximum Reserved Capacity in the period.

2. Discounts

Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by Eversource must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, Eversource must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

3. Resales

The rates and rules governing charges and discounts in Sections I.A.1 and 2 of this Schedule ES-3 stated above shall not apply to resales of transmission service, compensation for which shall be governed by Schedule 21.

4. Credit to the Transmission Charge

Whenever service provided hereunder is interrupted or curtailed by Eversource, the Local Control Center or the New England System Operator, the Transmission Charges to the Transmission Customer calculated pursuant to Section A, of this Schedule ES-3 shall be credited by an amount equal to the sum of the credits calculated for each hour of interruption or curtailment in service.

The credit to the Transmission Customer for each such hour of interruption or curtailment shall be calculated as the product of (i) the applicable equivalent hourly charge for hourly, daily, weekly, or monthly transactions, and (ii) the kilowatts of service interruption or curtailment during such hour.

5. Eversource's Annual Formula Rate for Non Firm Point-To-Point Transmission Service

Eversource's Annual Formula Rates for Non Firm Point-To-Point Transmission Service shall be expressed in $ per kilowatt-year and shall be determined in accordance with the rate formulas specified in Appendix A of this Schedule ES-3 ("Formula Rates").

6. Tax Rates and Taxes

The Formula Rates set forth in this Schedule ES-3 in effect during a Service Year shall be based on local, state, and federal tax rates and taxes in effect during the Service Year. If, at any time, additional or new taxes are imposed on Eversource or existing taxes are removed, the Formula Rate will be appropriately modified and filed with the Commission in accordance with Part 35 of the Commission's regulations.

II. In addition to the applicable charges of this Local Service Schedule, and as otherwise specified in the Service Agreement, the Transmission Customer shall pay Eversource Service each month the following additional charges for Non-firm Point-To-Point Transmission Service provided during such month.

A. Taxes and Fees Charge

B. Regulatory Expenses Charge

C. Other

A. **TAXES AND FEES CHARGE**

If any governmental authority requires the payment of any fee or assessment or imposes any form of tax with respect to payments made for Non-Firm Point-To-Point Transmission Service provided under this Local Service Schedule, not specifically provided for in any of the charge or rate provisions under this Local Service Schedule, including any applicable interest charged on any deficiency assessment made by the taxing authority, together with any further tax on such payments, the obligation to make payment for such fee, assessment, or tax shall be borne by the Transmission Customer. Eversource will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's regulations.

B. **REGULATORY EXPENSES**

Eversource reserves its rights to make a Section 205 filing for recovery of its costs to administer this Local Service Schedule and the Service Agreements.

C. **OTHER**

Eversource shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Schedule ES-3 in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE ES-3

Appendix A

CATEGORY A RATE

FOR NON-FIRM POINT-TO-POINT SERVICE

Eversource’s Category A Formula Rate for Non-Firm Point-To-Point Transmission Service ("Formula Rate") is an annual rate determined from the following formula.

$$\text{Formula Rate}_i = (A_i - B_i + C_i - D_i) / E_i$$

WHERE:

- i equals the Service Year.

- A is the annual Total Transmission Revenue Requirements (expressed in dollars) as described in Attachment ES-H.

- B is the revenues received (expressed in dollars) from the provision of transmission and other related services to others as recorded in FERC Accounts 456.1 and 454 to the extent that such transactions are not included in the determination of load (E),[2] minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

- C is the transmission payments (expressed in dollars) to the New England System Operator as recorded in FERC Account 565 in accordance with the Tariff.

- D is the sum of the annual revenues received (expressed in dollars) for the costs associated with the Localized Facilities, minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

- E is the average Eversource Monthly Transmission System Category A Load (expressed in kilowatts).

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[2] Includes amortization of revenues from point-to-point transmission service provided to Consolidated Edison Energy Massachusetts, Inc. and NRG Energy, Inc. under contracts in which customers paid based on single lump sum payment.

SCHEDULE ES-3[RESERVED]

SCHEDULE ES-4

CHARGE PROVISIONS FOR LOCAL NETWORK SERVICE

I. Network Customers will pay the following demand charges for Local Network Service.

A. **DEMAND CHARGE A**

1. Determination of Demand Charge:
The Demand Charge will be determined in accordance with Section ~~16.3~~16.4 of this Local Service Schedule.

2. Eversource's Annual Transmission Revenue Requirements:
The annual Transmission Revenue Requirements shall be determined in accordance with the formula specified in Appendix A of this Schedule ES-4 ("Formula Requirements").

B. **DEMAND CHARGE B**

1. Determination of Demand Charge
The Demand Charge will be determined in accordance with Section ~~16.3~~16.4 of this Local Service Schedule.

2. Eversource Annual Transmission Revenue Requirements:
The annual Transmission Revenue Requirements for each Localized Facility of a Designated State or Area shall be determined in accordance with the formula specified in Appendix B of this Schedule ES-4 ("Formula Requirements").

C. TAX RATES AND TAXES

The Formula Requirements set forth in this Schedule ES-4 in effect during a Service Year shall be based on local, state, and federal tax rates and taxes in effect during the Service Year. If, at any time, additional or new taxes are imposed on Eversource or existing taxes are removed, the Formula Requirements will be appropriately modified and filed with the Commission in accordance with Part 35 of the Commission's regulations.

II. In addition to the applicable charges of this Local Service Schedule, and as otherwise specified in the Service Agreement, the Transmission Customer shall pay to Eversource Service each month the following additional charges for Local Network Service provided during such month.

A. Taxes and Fees Charge

B. Regulatory Expenses Charge

C. Other

A. **TAXES AND FEES CHARGE**

If any governmental authority requires the payment of any fee or assessment or imposes any form of tax with respect to payments made for service provided under this Local Service Schedule, not specifically provided for in any of the charge or rate provisions under this Local Service Schedule, including any applicable interest charged on any deficiency assessment by the taxing authority, together with any further tax on such payments, the obligation to make payment for any such fee, assessment, or tax shall be borne by the Transmission Customer. Eversource will make a separate filing with the Commission for recovery of any such costs in accordance with Part 35 of the Commission's regulations.

B. **REGULATORY EXPENSES CHARGE**

Eversource shall have the right to make a Section 205 filing for recovery of regulatory expenses associated with this Local Service Schedule and the Service Agreements.

C. **OTHER**

Eversource shall have the right, at any time, unilaterally to file for a change in any of the provisions of this Schedule ES-4 in accordance with Section 205 of the Federal Power Act and the Commission's implementing regulations.

SCHEDULE ES-4

Appendix A

NETWORK FORMULA REQUIREMENTS

FOR CATEGORY A COSTS

Eversource's formula requirements for Local Network Service is determined from the following formula.

$$\text{Formula Requirements}_i = A_i - B_i + C_i - D_i$$

WHERE:

- $_i$ equals the Service Year.

- A is the annual Total Transmission Revenue Requirements (expressed in dollars) as described in Attachment ES-H.

- B is the revenues received (expressed in dollars) from the provision of transmission and other related services to others as recorded in FERC Accounts 456.1 and 454 to the extent that such transactions are not included in the determination of load,[2] minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

- C is the transmission payments to (expressed in dollars) the New England System Operator as recorded in FERC Accounts 565 in accordance with the Tariff.

- D is the sum of the annual revenues received (expressed in dollars) for the costs associated with Localized Facilities, minus any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment.

---

[2] Includes amortization of revenues from point-to-point transmission service provided to Consolidated Edison Energy Massachusetts, Inc. and NRG Energy, Inc. under contracts in which customers paid based on single lump sum payment.

SCHEDULE ES-4

Appendix B

NETWORK FORMULA REQUIREMENTS

FOR CATEGORY B COSTS

Eversource's formula requirements for Local Network Service and for Eligible Customers taking Regional Network Service under this Tariff in a Designated State or Area of a Localized Facility, is determined from the following formula, and separately determined for each Designated State or Area of a Localized Facility.

$$\text{Formula Requirements}_i = D_i$$

WHERE:

- $_i$ equals the Service Year.

- D is the annual Localized Transmission Revenue Requirements (expressed in dollars) of the Localized Facilities of Eversource for a Designated State or Area of a Localized Facility, as described in Attachment ES-I.

ATTACHMENT ES-C

AVAILABLE TRANSFER CAPABILITY METHODOLOGY

TABLE OF CONTENTS

1. Introduction

ISO is the regional transmission organization ("RTO"), serving the New England Control Area. ISO is responsible for the development, oversight, and fair administration of New England's wholesale market, management of the bulk electric power system and wholesale markets' planning processes. The ISO serves as the Balancing Authority for the New England Control Area. The New England Control Area is interconnected to three neighboring Balancing Authority Areas ("BAA"): New Brunswick System Operator Area ("NBSO Area"), New York Independent System Operator Area ("NYISO Area"), and Hydro-Quebec TransEnergie Area ("HQTE Area").

As part of its RTO responsibilities, the ISO is registered with the North American Electric Reliability Corporation ("NERC") as several functional model entities that have responsibilities related to the calculation of ATC as defined in the following NERC Standards: MOD-001 – Available Transmission System Capability ("MOD-001"), MOD-004 – Capacity Benefit Margin ("MOD-004"), and MOD-008 – Transmission Reliability Margin Calculation Methodology ("MOD-008"). The extent of those responsibilities is based on various Commission approved transmission operating agreements and the provisions of the ISO New England Operating Documents.

While the ISO is the Transmission Service Provider for Regional Network Service ("Regional Transmission Service") associated with Pool Transmission Facilities, the Participating Transmission Owners ("PTOs") provide local transmission service over Non-Pool Transmission Facilities within the RTO footprint and are responsible for calculating TTC and ATC associated with Local Transmission Service provided under Schedule 21 pursuant to the Transmission Operating Agreement ("TOA"). Pursuant to CFR § 37.6(b)[1] of the FERC Regulations Transmission Provider's are obligated to calculate and post TTC and ATC for each Posted Path. The ISO is not responsible for the calculation of these values.

Pursuant to the terms of the Transmission Operating Agreement executed between the companies comprising Eversource hereunder as Participating Transmission Owners ("PTOs") and ISO, Eversource is a Transmission Service Provider and calculates TTC and ATC for certain Local Facilities over which Point-to-Point transmission service is provided under Schedule 21-ES of the ISO Open Access Transmission Tariff ("ISO OATT").

[1] §37.6(b) Posting transfer capability. The available transfer capability on the Transmission Provider's system (ATC) and the total transfer capability (TTC) of that system shall be calculated and posted for each Posted Path as set out in this section.

Posted Path is defined as any control area to control area interconnection; any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a customer requests to have ATC or TTC posted. For this last category, the posting must continue for 180 days and thereafter until 180 days have elapsed from the most recent request for service over the requested path. For purposes of this definition, an hour includes any part of any hour during which service was denied, curtailed or interrupted (§37.6(b)(1)(i)).

Non-PTF facilities are primarily radial paths that provide transmission service directly to interconnected generators. It is possible, in the future that a particular path may interconnect more nameplate capacity generation than the path's TTC. However, for Eversource's Non-PTF modeled by the ISO or the Local Control Center ("LCC"), the ISO or the LCC will only dispatch an amount of generation interconnected to such path so as not to incur a reliability or stability violation on the subject path consistent with ISO's economic, security constrained dispatch methodology.

Eversource does not currently have any Posted Paths based on the above definition. However, if Eversource does have any Posted Path(s) in the future, Eversource will calculate TTC using NERC Standard MOD-029-1 Rated System Path Methodology as outlined below.

1.1 Scope of Document

The scope of this document is limited to those functions performed or utilized by Eversource as the Transmission Provider of Schedule 21-ES Local Point-to Point transmission service over Non-PTF pursuant to the PTOs' Transmission Operating Agreement and the ISO OATT:

- Total Transfer Capability (TTC) methodology
- Available Transfer Capability (ATC) methodology
- Existing Transmission Commitment (ETC)
- Use of Rollover Rights (ROR) in the calculation of ETC

As explained in Section 2, TTC and ATC are required to be calculated only for certain non-PTF internal Posted Paths over which Local Point-to-Point transmission service is provided under Schedule 21-ES. TTC and ATC is not calculated by Eversource for Local Network Service because ISO employs a market model for economic, security constrained dispatch of generation, and Eversource does not require advance reservation for such network service.

2. Transmission Service in the New England Markets

Since the inception of the OATT for New England, the process by which generation located inside New England supplies energy to the bulk electric system has differed from the Commission's pro forma OATT. The fundamental difference is that internal generation is dispatched in an economic, security constrained manner by the ISO rather than utilizing a system of physical rights, advance reservations and point-to-point transmission service. Through this process, internal generation provides offers that are utilized by the ISO in the Real-Time Energy Market dispatch software. This process provides the least-cost dispatch to satisfy Real-Time load on the system.

In addition to offers from generation within New England, entities may submit External Transactions to move energy into the ISO Area, the New England Control Area, out of the New England Control Area, or through the New England Control Area. The Real-Time Energy Market clears these External Transactions based on forecast Locational Marginal Pricing (LMPs) and the transfer capability of the associated external interfaces. With those External Transactions in place, the Real-Time Energy Market dispatches internal generation in an economic, security constrained manner to meet Real-Time load within the region.

This process for submitting External Transactions into the New England Real-Time Energy Market does not require an advance physical reservation for use of the PTF. In the event that the net of the economic External Transactions is greater than the transfer capability of the associated external interface, the External Transactions selected to flow are selected based on the rules specified in the Tariff. For any External Transactions that are confirmed to flow in Real-Time based on the economics of the system, a transmission reservation for RNS and Through or Out Service is created after-the-fact to satisfy the transparency needs of the market.

The process described above is applicable to the PTF within the ISO Area, and non-PTF Local Facilities where utilized for Local Network Service by generation or load. However, Eversource owns Local Facilities over which an advance transmission service reservation for firm or non-firm transmission service may be required. On those Local Facilities, the market participant may obtain a transmission service reservation from Eversource under Schedule 21-ES prior to delivery of energy into the New England Wholesale Market. This document addresses the calculation of ATC and TTC for these non-PTF internal paths.

3. Eversource **Total Transfer Capability (TTC)**

The Total Transfer Capability (TTC) is the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions. TTC for Schedule 21-ES is calculated using NERC Standard MOD-029-1 Rated System Path Methodology and posted on Eversource's OASIS site.

Eversource will calculate and post TTC on its OASIS site for all non-PTF Posted Paths that are eligible for Point-to-Point transmission service reservations. The TTC on Eversource's non-PTF Local Facilities that are eligible for Local Point-to-Point transmission service reservations are relatively static values. Eversource thus calculate the TTC for Non-PTF Posted Paths that may require Local Point-to-Point Local Point-to-Point transmission reservations on its OASIS provider page according to NAESB Standards.

4. Capacity Benefit Market (CBM)

CBM is defined as the amount of firm transmission transfer capability set aside by a TSP for use by the Load Serving Entities. The ISO does not set aside any CBM for use by the Load Serving Entities, because of the New England approach to capacity planning requirements in the ISO New England Operating Documents. Load Serving Entities operating within the New England Control Area are required to arrange for their Capacity Requirements prior to the beginning of any given month in accordance with ISO Tariff, Section III.13.7.3.1 (Calculation of Capacity Requirement and Capacity Load Obligation). Load Serving Entities do not utilize CBM to ensure that their capacity needs are met; therefore, CBM is not applicable within the New England market design. Accordingly, for purposes of Eversource's ATC calculation and because CBM for the New England Control Area is set to zero (0), Eversource utilizes a zero (0) CBM value.

Existing Transmission Commitments, Firm (ETC_F)

The ETC_F are those confirmed Firm transmission reservations (PTP_F) plus any rollover rights for Firm transmission reservations (ROR_F) that have been exercised. There are no allowances necessary for Native Load forecast commitments (NL_F), Network Integration Transmission Service ($NITS_F$),

grandfathered Transmission Service (GF_F) and other service(s), contract(s) or agreement(s) (OS_F) to be considered in the ETC_F calculation.

Existing Transmission Commitments, Non-Firm(ETC_{NF})

The (ETC_{NF}) are those confirmed Non-Firm transmission reservations (PTP_{NF}). There are no allowances necessary for Non-Firm Network Integration Transmission Service ($NITS_{NF}$), Non-Firm grandfathered Transmission Service (GF_{NF}) or other service(s), contract(s) or agreement(s) (OS_{NF}).

5. Transmission Reliability Margin (TRM)

TRM is the amount of transmission transfer capability set aside to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. It is used only for external interfaces under the New England market design. Eversource does not have any external interfaces, and therefore TRM for Eversource's non-PTF facilities is zero.

6. Calculation of ATC for Eversource's Local Facilities - General Description:

NERC Standards MOD-001-1 – Available Transmission System Capability and MOD-029-1 – Rated System Path Methodology define the required items to be identified when describing a transmission provider's ATC methodology. As a practical matter, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

Common practice is not to calculate or post firm and non-firm ATC values for the non-PTF assets described above, as ATC is positive and listed as 9999. Transmission customers are not restricted from reserving firm or non-firm transmission service on non-PTF facilities.

As Real-Time approaches, the ISO utilizes the Real-Time energy market rules to determine which of the submitted energy transactions will be scheduled in the coming hour. Basically, the ATC of the non-PTF assets in the New England market is almost always positive. With this simplified version of ATC, there is no detailed algorithm to be described or posted. Thus, for those non-PTF facilities that serve as a path for Eversource's Schedule 21-ES Point-to-Point Transmission Customers, Eversource has posted the ATC as 9999, consistent with industry practice. ATC on these paths varies depending on the time of day.

However, it is posted with an ATC of "9999" to reflect the fact that there are no restrictions on these paths for commercial transactions.

6.1 Calculation of Schedule 21-ES Firm ATC (ATC_F)

6.1.1 Calculation of ATC_F in the Planning Horizon (PH)

For purposes of this Attachment C PH is any period before the Operating Horizon.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for TRM, CBM, ETC_F, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM are zero. Firm Transmission Service under Schedule 21-ES that is available in the Planning Horizon (PH) includes: Yearly, Monthly, Weekly, and Daily. $Postbacks_F$ and $counterflows_F$ of Schedule 21-ES transmission reservations are not considered in the ATC calculation. Therefore, ATC_F in the PH is equal to the TTC minus ETC_F

6.1.2 Calculation of ATC_F in the Schedule 21-ES Operating Horizon (OH)

For purposes of this Attachment C OH is noon eastern prevailing time each day. At that time, the OH spans from noon through midnight of the next day for a total of 36 hours. As time progresses, the total hours remaining in the OH decreases until noon the following day when the OH is once again reset to 36 hours.

Consistent with the NERC definition, ATC_F is the capability for Firm transmission reservations that remain after allowing for ETC_F, CBM, TRM, $Postbacks_F$ and $counterflows_F$.

As discussed above, TRM and CBM is zero. Daily Firm Transmission Service under Schedule 21-ES is the only firm service offered in the Operating Horizon (OH). $Postbacks_F$ and $counterflows_F$ of Schedule 21-ES transmission reservations are not considered in the ATC_F calculation. Therefore, ATC_F in the OH is equal to the TTC minus ETC_F.

6.1.3 Because Firm Schedule 21-ES transmission service is not offered in the Scheduling Horizon (SH): ATC_F in the SH is zero.

6.2 Calculation of Schedule 21-ES Non-Firm ATC (ATC_{NF})

6.2.1 Calculation of ATC_{NF} in the PH

ATC_{NF} is the capability for Non-Firm transmission reservations that remain after allowing for ETC_F, ETC_{NF}, scheduled CBM (CBM_S), unreleased TRM (TRM_U), Non-Firm Postbacks ($Postbacks_{NF}$) and Non-Firm counterflows ($counterflows_{NF}$).

As discussed above, the TRM and CBM for Schedule 21-ES are zero. Non-Firm ATC available in the PH includes: Monthly, Weekly, Daily and Hourly. TRM_U, $Postbacks_{NF}$ and $counterflows_{NF}$ of Schedule 21-ES transmission reservations are not considered in this calculation. Therefore, ATC_{NF} in the PH is equal to the TTC minus ETC_F and ETC_{NF}.

6.2.2 Calculation of ATC_{NF} in the OH

ATC_{NF} available in the OH includes: Daily and Hourly.

As discussed above TRM and CBM for Schedule 21-ES are zero. TRM_U, counterflows and ETC_{NF} are not considered in this calculation. Therefore, ATC_{NF} in the OH is equal to the TTC minus ETC_F, plus postbacks of PTP_F in OH as PTP_{NF} ($Postbacks_{NF}$)

6.3 Negative ATC

As stated above, the ratings of the radial transmission paths are always higher than the transmission requirements of the Transmission Customers connected to that path. As such, transmission services over these posted paths are considered to be always available.

As stated above, Eversource’s non-PTF facilities are primarily radial paths that provide transmission service to directly interconnected generators. It is possible, in the future, that a particular radial path may interconnect more nameplate capacity generation than the path’s TTC. However, due to the ISO’s security constrained dispatch methodology, the ISO will only dispatch an amount of generation interconnected to such path so as not to incur a reliability or stability violation on the subject path. Therefore, ATC in the PH, OH and SH may become zero, but will not become negative.

7. Posting of Schedule 21-ES ATC

7.1 Location of ATC Posting

ATC values are posted on Eversource’s OASIS site.

7.2 Updates To ATC

When any of the variables in the ATC equations change, the ATC values are recalculated and immediately posted.

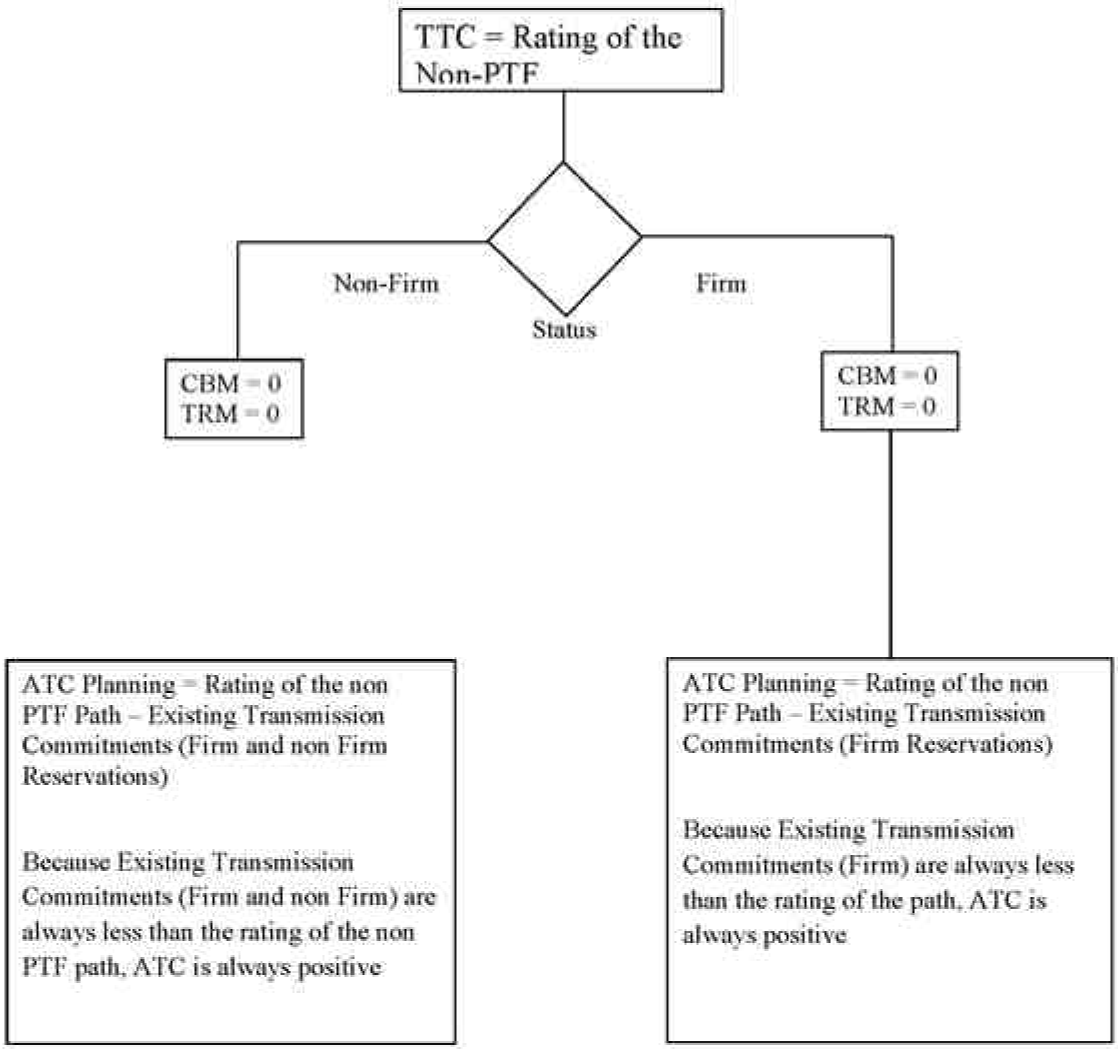
7.3 Coordination of ATC Calculations

Schedule 21-ES non-PTF has no external interfaces. Therefore it is not necessary to coordinate the values.

7.4 Mathematical Algorithms A link to the actual mathematical algorithm for the calculation of ATC for the Eversource non-PTF internal interfaces is located at https://www.eversource.com/Content/docs/default-source/Tranmission/attachment-6.pdf?sfvrsn=0.

8. Process Flow Diagram for ATC Calculation

Non-PTF Transmission Path ATC Process Flow Diagram



ATTACHMENT ES-D
PENALTY DISBURSEMENT METHODOLOGY

Late Study Penalties: Penalties paid by the Transmission Provider pursuant to Schedule 21 are referred to as "Late Study Penalties," and therefore subject to distribution to all Transmission Customers that are not affiliated with the Transmission Provider. On the month following the end of each calendar quarter, each Transmission Customer that is not affiliated with the Transmission Provider shall receive, on the relevant monthly invoice, a credit for its share of the Late Study Penalties that were assessed during the applicable calendar quarter. The Transmission Customer’s share of the Late Study Penalties (if any) will be determined as follows:

(a) For each quarter, the Transmission Provider will determine: (1) the sum of all Late Study Penalties assessed during the quarter measured in dollars (LSRq), and (2) the sum of all transmission revenue from Transmission Customers that are not affiliated with the Transmission Provider during that quarter, measured in dollars (LSTRq). Where:

LSRq =	Late Study Penalty Revenue in the quarter
LSTRq =	Transmission Revenue from Transmission Customers not affiliated with the Transmission Provider in the quarter

(b) For each quarter, each Transmission Customer that was not affiliated with the Transmission Provider will receive a credit equal to the product of (i) LSRq multiplied by (ii) a fraction derived from dividing the amount of transmission revenue from that Transmission Customer (TC1) during that quarter (measured in dollars), where TC1 is equal to one Transmission Customer, and a denominator equal to LSTRq.

(c) The Transmission Provider shall apply the credit for Late Study Penalties to service that the non-affiliated Transmission Customer takes from the Transmission Provider pursuant to this Schedule 21-ES. Any remaining credit will be refunded to the Transmission Customer.

ATTACHMENT ES-E

LOCALIZED COSTS RESPONSIBILITY **AGREEMENT**

This Localized Costs Responsibility Agreement ("LCRA" or "Agreement"), dated as of _______________________, is entered into by and between the Eversource Energy Service Company ("Eversource Service" or "COMPANY"), acting as agent for [The Connecticut Light and Power Company, Western Massachusetts Electric Company, Public Service Company of New Hampshire], andthe "Transmission Customer".

The Transmission Customer is _____________________________________. The Transmission Customer has been determined to be an Eligible Customer taking Regional Network Service under the Tariff whose load **is located in the** Designated State or Area for a **Localized** Facility listed in **Section** 16.3 **of** Schedule 21-ES of the Tariff**.**

The Transmission Customer agrees to pay its portion of the cost of Localized Facilities in the Designated State or Area in which the Transmission Customer's load is located as provided in the Tariff and in accordance with Commission orders. Billing under this Agreement shall commence on the later of: (1) 0001 hours on _____________________, or (2) such other date as permitted by the Commission.

Charges under this Agreement shall terminate on the earlier of: (1) the date on which the costs of the Localized Facilities in the Designated State or Area in which the Transmission Customer's load is located are fully depreciated; or (2) the date upon which the Transmission Customer no longer takes Regional Network Service under the Tariff in the Designated State or Area in which the Transmission Customer's load is located; provided, that the Transmission Customer shall remain responsible for all final payment obligations. In the event that the Transmission Customer sells or assigns, or transfers its load to another entity ("New Transmission Customer"), the Transmission Customer must provide Eversource Service with at least ninety (90) calendar days advance written notice of the sale, assignment, or transfer.

The Transmission Customer shall remain liable for the performance of all obligations under this Agreement until a new LCRA has been executed between the New Transmission Customer and Eversource Service, or in the case of an unexecuted LCRA, such other date as it has been **permitted to** be made effective by the Commission. No sale or assignment shall **become effective** until the Parties have complied with all Applicable Laws and Regulations required for such sale, assignment, or transfer**.**

Other special provisions (if any)

____.

Any notice or request made to or by any Party regarding this greement shall be made in writing and shall be telecommunicated or delivered either in person, or by prepaid mail (return receipt requested) to the representative of the other Party as indicated below. Such representative and address for notices or requests may be changed from time to time by notice by one Party to the other.

COMPANY:

____

____

____

TRANSMISSION CUSTOMER:

____

____

____

Any exhibits to thisAgreement and the Tariff are incorporated herein and made a part hereof. ThisAgreement may be amended, from time to time, as provided for in Schedule 21-ES of the Tariff.

IN WITNESS WHEREOF, the Parties have caused thisAgreement to be executed by their respective authorized officials as of the date first above written.

EVERSOURCE ENERGY SERVICE COMPANY

By: ____________________________________

Its ________________________

TRANSMISSION CUSTOMER

By: __________________________________

Its   ____________________________________

ATTACHMENT ES-G

NETWORK OPERATING AGREEMENT

This Network Operating Agreement is an appendix to Schedule 21-ES (this Local Service Schedule) of the OATT and operates as an implementing agreement for Local Network Service under this Local Service Schedule. This Network Operating Agreement is subject to and in accordance with Part III of this Local Service Schedule. All definitions and other terms and conditions of this Local Service Schedule are incorporated herein by reference.

1.0 Definitions:

1.1 Data Acquisition Equipment

Supervisory control and data acquisition ("SCADA"), remote terminal units ("RTUs") to obtain information from a Party's facilities, telephone equipment, leased telephone circuits, fiber optic circuits, and other communications equipment necessary to transmit data to remote locations, and any other equipment or service necessary to provide for the telemetry and control requirements of this Local Service Schedule.

1.2 Data Link

The direct communications link between the Transmission Customer's energy control center and Eversource's designated location(s) that will enable Eversource to receive real time telemetry and data from the Transmission Customer.

1.3 Metering Equipment

High accuracy, solid state kW, kVAR, kWh meters, metering cabinets, metering panels, conduits, cabling, high accuracy current transformers and high accuracy potential transformers, which directly or indirectly provide input to meters or transducers, metering recording devices, telephone circuits, signal or pulse dividers, transducers, pulse accumulators, metering sockets, test switch devices, enclosures, conduits, and any other metering, telemetering or communication equipment necessary to implement the provisions of this Local Service Schedule.

1.4 Protective Equipment

Protective relays, relaying panels, relaying cabinets, circuit breakers, conduits, cabling, current transformers, potential transformers, coupling capacitor voltage transformers, wave traps, transfer trip and

fault recorders, which directly or indirectly provide input to relays, fiber optic communication equipment, power line carrier equipment and telephone circuits, and any other protective equipment necessary to implement the protection provision of this Local Service Schedule.

2.0 Term

The term shall be as provided in the Service Agreement consistent with this Local Service Schedule (including, but not limited to, application procedures, commencement of service, and effect of termination).

3.0 Point(s) Of Interconnection

Local Network Service will be provided by Eversource at the point(s) of interconnection specified in Appendix __, as amended from time to time. Each point of interconnection in this listing shall have a unique identifier, meter location, meter number, metered voltage, terms on meter compensation and designation of current or future year of in service.

4.0 Cogeneration And Small Power Production Facilities

If a Qualifying Facility is located or locates in the future on the System of the Transmission Customer, and the owner or operator of such Qualifying Facility sells the output of such Qualifying Facility to an entity other than the Transmission Customer, the delivery of such Qualifying Facility's power shall be subject to and contingent upon transmission arrangements being established with Eversource prior to commencement of delivery of any such power and energy.

5.0 Character Of Service

Network Transmission Service at the points of interconnection shall be in the form of single phase or balanced three-phase alternating current at a frequency of sixty (60) hertz. The Transmission Customer shall operate and maintain its electric system in a manner that avoids: (i) the generation of harmonic frequencies exceeding the limits established by the latest revision of IEEE-519; (ii) voltage flicker exceeding the limits established by the latest revision of IEEE-141; (iii) negative sequence currents; (iv) voltage or current fluctuations; (v) frequency variations; or (vi) voltage or power factor levels that could adversely affect Eversource’s electrical equipment or facilities or those of its customers, and in a manner that complies with all applicable NERC, NPCC, ISO and Eversource’s operating criteria, rules, regulations, procedures, guidelines and interconnection standards as amended from time to time.

6.0 Continuity Of Service

(a) Eversource and the Transmission Customer shall operate and maintain their respective network systems, in accordance with Good Utility Practice, and in a manner that will allow Eversource to safely and reliably operate the Eversource Transmission System in accordance with this Local Service Schedule, so that either Party shall not unduly burden the other Party; provided, however, that notwithstanding any other provision of this Local Service Schedule, Eversource shall retain the sole responsibility and authority for all operating decisions that could affect the integrity, reliability and security of the Eversource Transmission System.

(b) Eversource shall exercise reasonable care and Due Diligence to ensure Local Network Service hereunder in accordance with Good Utility Practice; provided, however, that Eversource shall not be responsible for any failure to ensure electric power service, nor for interruption, reversal or abnormal voltage of the service, if such failure, interruption, reversal or abnormal voltage is due to a Force Majeure.

7.0 Power Factor

(a) Where Local Network Service provided under this Local Service Schedule is for delivery of power to a load center of the Transmission Customer served from the Eversource Transmission System, the Transmission Customer shall maintain load power factor levels, during both on- and off- peak hours, appropriate to meet the operating requirements of Eversource, and shall follow the ISO standards and practices, as set forth in the Service Agreement.

(b) Where Local Network Service provided under this Local Service Schedule is for delivery of power from a generating facility connected to the Eversource Transmission System, the Transmission Customer shall deliver power at a lagging or leading power factor as set forth in the Service Agreement.

(c) Where Local Network Service provided under this Local Service Schedule is for delivery of power from outside the Eversource Transmission System, the obligation to maintain proper sending and receiving end voltages rests with the Transmission Customer, as set forth in the Service Agreement.

(d) In the event that the power factor levels and reactive supply requirements set forth in the Service Agreement are not maintained by the Transmission Customer, Eversource shall thereupon have the right to take the appropriate corrective action and to charge the Transmission Customer for the costs thereof.

Eversource shall have the right, at any time, unilaterally to make a Section 205 filing with the Commission for the recovery of any such costs.

8.0 Metering

(a) The Transmission Customer shall, at its expense, purchase all necessary metering equipment to accurately account for the electric power being transmitted under this Local Service Schedule. Eversource may require the installation of telemetering equipment for the purposes of billing, power factor measurements and to allow Eversource to maximize economic and reliable operation of its transmission system. Such metering equipment shall meet the specifications and accepted metering practices of Eversource and applicable criteria, rules, standards and operating procedures, or such successor rules and standards. At Eversource’s option, communication metering equipment may be installed in order to transmit meter readings to Eversource’s designated locations.

(b) Electric power being transmitted under this Local Service Schedule will be measured by meters at all points of interconnection and/or on generating facilities (Network and non-Network Resources) located on and outside the Transmission Customer's system as required by Eversource.

(c) The Transmission Customer shall purchase meters capable of time-differentiated (by hour) measurement of the instantaneous flow in kW and net active power flow in kWh and of reactive power flow. All meters shall compensate for applicable line and/or transformer losses in accordance with Good Utility Practice when measurement is made at any location other than the point of interconnection.

(d) Eversource reserves the right: (i) to determine metering equipment ownership; (ii) to determine the equipment installation at each point of interconnection; (iii) to require the Transmission Customer to install the equipment -- or -- install the equipment with the Transmission Customer supplying without cost to Eversource a suitable place for the installation of such equipment; (iv) to determine other equipment allowed in the metering circuit; (v) to determine metering accuracy requirements; (vi) to determine the responsibilities for operation, maintenance, testing and repair of metering equipment.

(e) Eversource shall have access to metering data, including telephone line access, which may reasonably be required to facilitate measurement and billing under this Local Service Schedule. Eversource may require the Transmission Customer provide, at its expense, a separate dedicated voice grade telephone circuit for Eversource and the Transmission Customer to remotely access each meter.

Metering equipment and data shall be accessible at all reasonable hours for purposes of inspection and reading.

(f) All metering equipment shall be tested in accordance with practices of Eversource, applicable criteria, rules, standards and operating procedures or upon the request by Eversource. If at any time metering equipment fails to register or is determined to be inaccurate, in accordance with Eversource's practices and applicable criteria, rules, standards and operating procedures, the Transmission Customer shall make the equipment accurate as soon thereafter as practicable, and the meter readings and rate computation for the period of such inaccuracy, insofar as can reasonably be ascertained, shall be adjusted; provided, however, that no adjustment to charges shall be required for any period exceeding two (2) months prior to the date of the test. Representatives of Eversource will be afforded opportunity to witness such tests.

9.0 Network Load

The Transmission Customer shall provide Eversource with the actual hourly Network Load for each calendar month by the seventh day of the following calendar month.

10.0 Data Transfer:

(a) The Transmission Customer shall provide timely, accurate real time information to Eversource in order to facilitate performance of its obligations under this Local Service Schedule.

(b) The selection of real time telemetry and data to be received by Eversource and the Transmission Customer shall be necessary for safety, reliability, security, economics, and/or monitoring of real-time conditions that affect the Eversource Transmission System. This telemetry shall include, but is not limited to, loads, line flows (MW and MVAR), voltages, generator output, and status of substation equipment at any of the Transmission Customer's transmission and generation facilities. To the extent that Eversource or the Transmission Customer requires data that are not available from existing equipment, the Transmission Customer shall, at its expense and at locations designated by Eversource or the Transmission Customer, install any metering equipment, data acquisition equipment, or other equipment and software necessary for the telemetry to be received by Eversource or the Transmission Customer. Eversource shall have the right to inspect equipment and software associated with the data transfer in order to assure conformance with Good Utility Practices.

11.0 Maintenance of Equipment

The Transmission Customer shall, on a regular basis in accordance with practices of Eversource, applicable criteria, rules, standards and operating procedures or at the request of Eversource, and at its expense, test, calibrate, verify and validate the data link, metering equipment, data acquisition equipment, transmission equipment, protective equipment and other equipment or software used to implement the provisions of this Local Service Schedule. Eversource shall have the right to inspect such tests, calibrations, verifications and validations of the data link, metering equipment, data acquisition equipment, transmission equipment, protective equipment and other equipment or software used to implement the provisions of this Local Service Schedule. Upon Eversource's request, the Transmission Customer will provide Eversource a copy of the installation, test and calibration records of the data link, metering equipment, data acquisition equipment, transmission equipment, protective equipment and other equipment or software. Eversource shall, at the Transmission Customer's expense, have the right to monitor the factory acceptance test, the field acceptance test, and the installation of any metering equipment, data acquisition equipment, transmission equipment, protective equipment and other equipment or software used to implement the provisions of this Local Service Schedule.

12.0 Notification

(a) The Transmission Customer shall notify and coordinate with Eversource prior to the commencement of any work or maintenance by the Transmission Customer, Network Member, or contractors or agents performing on behalf of either or both, which may directly or indirectly have an adverse effect on the Transmission Customer or Eversource's data link, or the reliability of the Eversource Transmission System. All notifications for scheduled outages of the data link, metering equipment, data acquisition equipment, transmission equipment, protective equipment and other equipment or software must meet the requirements of the ISO and Eversource.

13.0 Emergency System Operations

(a) The Transmission Customer, at its expense, shall be subject to all applicable emergency operation standards promulgated by NERC, NPCC, ISO and Eversource which may include but not limited to underfrequency relaying equipment, load shedding equipment and voltage reduction equipment.

(b) Eversource reserves the right to take whatever actions they deem necessary to preserve the integrity of the Eversource Transmission System during emergency operating conditions. If the Local Network Service at the points of interconnection is causing harmful physical effects to the Eversource

Transmission System facilities or to its customers (e.g., harmonics, undervoltage, overvoltage, flicker, voltage variations, etc.), Eversource shall promptly notify the Transmission Customer and if the Transmission Customer does not take the appropriate corrective actions immediately, Eversource shall have the right to interrupt Local Network Service under this Local Service Schedule in order to alleviate the situation and to suspend all or any portion of Local Network Service under this Local Service Schedule until appropriate corrective action is taken.

(c) In the event of any adverse condition or disturbance on the Eversource Transmission System or on any other system directly or indirectly interconnected with the Eversource Transmission System, Eversource may, as it deems necessary, take actions or inactions that, in Eversource's sole judgment, result in the automatic or manual interruption of Local Network Service in order to: (i) limit the extent or damage of the adverse condition or disturbance; (ii) prevent damage to generating or transmission facilities; (iii) expedite restoration of service; or (iv) preserve public safety.

14.0 Cost Responsibility

(a) The Transmission Customer shall be responsible for the costs incurred by the Transmission Customer and Eversource to implement the provisions of this Local Service Schedule including, but not limited to, engineering, administrative and general expenses, material and labor expenses associated with the specifications, design, review, approval, purchase, installation, maintenance, modification, repair, operation, replacement, checkouts, testing, upgrading, calibration, removal, and relocation of equipment, or software.

(b) Additionally, the Transmission Customer shall be responsible for all costs incurred by the Transmission Customer and Eversource for on-going operation and maintenance of the metering, telecommunications and safety protection facilities and equipment required to implement the provisions of this Local Service Schedule. Such work shall include, but not limited to, normal and extraordinary engineering, administrative and general expenses, material, and labor expenses associated with the specifications, design, review, approval, purchase, installation, maintenance, modification, repair, operation, replacement, checkouts, testing, upgrading, calibration, removal, or relocation of equipment required to accommodate service under this Local Service Schedule.

15.0 Default

The Transmission Customer's failure to implement the terms and conditions of this Network Operating Agreement will be deemed to be a default under this Local Service Schedule and will result in Eversource seeking, consistent with FERC rules and regulations, immediate termination of service under this Local Service Schedule.

16.0 Regulatory Filings

Nothing contained in this Local Service Schedule or any associated Service Agreement, including this Network Operating Agreement, shall be construed as affecting in any way the right of Eversource to unilaterally make application to the Commission for a change in any portion of this Network Operating Agreement under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

IN WITNESS WHEREOF, the Parties have caused this Network Operating Agreement to be executed by their respective authorized officials as of the date written.

Date: __________________________

<u>Eversource Energy Service Company</u>
by: ________________________________
its Vice President

<u>Transmission Customer</u>
by: ________________________________
its ________________________________

ATTACHMENT ES-H

ANNUAL TRANSMISSION REVENUE REQUIREMENTS

Attachment ES-H Methodology:

This formula sets forth the method that Eversource will use to determine its annual Total Transmission Revenue Requirements. The Transmission Revenue Requirements reflect Eversource's total cost to own, operate and maintain the transmission facilities used for providing Open Access Transmission Service to transmission customers under this Local Service Schedule. The Transmission Revenue Requirements will be an annual formula rate calculation, effective for an initial term commencing on the effective date established by FERC and ending on May 31 of the following year. The calculation will be based on the previous calendar year's FERC Form 1 data, with an estimate of Eversource's current year average plant additions, Construction Work in Progress (CWIP), and the Allowance for Funds Used During Construction (AFUDC) regulatory liability account. Plant additions will be multiplied by a fixed charge carrying cost, and CWIP and the AFUDC regulatory liability account will be multiplied by the Cost of Capital. The revenue requirements will be updated thereafter each June 1 based on actual costs from the Service Year. The true-up information will be based on actual data, in lieu of allocated data if specifically identified in the FERC Form 1. For a capital addition whose cost exceeds $20 million, Eversource will make rate base adjustments to estimates and in the true-up process to represent the estimated and actual in-service dates for the capital addition. Specifically, Eversource will adjust for transmission plant, CWIP, AFUDC regulatory liability, accumulated depreciation and accumulated deferred taxes.

I. Definitions

Capitalized terms not otherwise defined in the Tariff and as used in this formula have the following definitions:

A. Allocation Factors

1. Transmission Wages and Salaries Allocation Factor shall equal the ratio of Eversource's Transmission-related direct wages and salaries, including those of affiliated companies, to Eversource's total direct wages and salaries, including those of affiliated companies, excluding administrative and general wages and salaries.

2. Plant Allocation Factor shall equal the ratio of the sum of total investment in Transmission Plant and Transmission Related General Plant to Total Plant in Service.

B. Terms

Administrative and General Expense shall equal Eversource's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928 and 930.1 and excluding Merger-Related Costs included in FERC Account Nos. 920-935 (other than those in FERC Account Nos. 924, 928 and 930.1, which have already been excluded).

AFUDC Regulatory Liability shall equal the unamortized balance of the capitalized AFUDC booked on Eversource's transmission projects as recorded in FERC Account 254 consistent with Commission orders.

Amortization of Loss on Reacquired Debt shall equal Eversource's expenses as recorded in FERC Account No. 428.1.

Amortization of Investment Tax Credits shall equal Eversource's credits as recorded in FERC Account No. 411.4.

Depreciation Expense for Transmission Plant shall equal Eversource's transmission expense as recorded in FERC Account No. 403.

Dispatch Center means CL&P's CONVEX dispatch center.

Dispatch Center Plant shall equal CL&P's gross plant balance for the Dispatch Center as recorded in FERC Account Nos. 350-359 and 389-399.

Dispatch Center Depreciation Expense shall equal the Dispatch Center depreciation expense as recorded in FERC Account No. 403.

Dispatch Center Amortization of Investment Tax Credits shall equal the Dispatch Center amortization of investment tax credits as recorded in FERC Account No. 411.4.

Dispatch Center Accumulated Deferred Income Taxes shall equal the net of Eversource's Dispatch Center deferred tax balance as recorded in FERC Account Nos. 281-283 and Eversource's Dispatch Center deferred tax balance as recorded in FERC Account No. 190.

Dispatch Center Municipal Tax Expense shall equal the Dispatch Center municipal tax expense as recorded in FERC Account Nos. 408.1 and 409.1.

General Plant shall equal Eversource's gross plant balance as recorded in FERC Account Nos. 389-399, less the Dispatch Center general plant.

General Plant Depreciation Expense shall equal Eversource's general plant expenses as recorded in FERC Account No. 403.

General Plant Depreciation Reserve shall equal Eversource's general plant reserve balance as recorded in FERC Account No. 108 less the portion of such reserve for the Dispatch Center.

Merger-Related Costs shall equal Eversource's amortized merger-related costs as authorized by FERC or by state regulatory order.

Other Regulatory Assets/Liabilities – FAS 106 shall equal the net of Eversource's FAS 106 balance as recorded in FERC Account No. 182.3 and any FAS 106 balance as recorded in Eversource's FERC Account No. 254.

Other Regulatory Assets/Liabilities – FAS 109 shall equal the net of Eversource's FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in Eversource's FERC Account No. 254.

Other Regulatory Assets/Liabilities – merger-related costs shall equal Eversource's unamortized balance of merger-related transmission costs recorded in FERC Account No. 182.3 as authorized by FERC.

Payroll Taxes shall equal those payroll expenses as recorded in Eversource's FERC Account Nos. 408.1 and 409.1.

Plant Held for Future Use shall equal Eversource's balance in FERC Account No. 105.

Prepayments shall equal Eversource's prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal Eversource's expenses as recorded in FERC Account No. 924.

Total Accumulated Deferred Income Taxes shall equal the net of Eversource's deferred tax balance as recorded in FERC Account Nos. 281-283 and Eversource's deferred tax balance as recorded in FERC Account No. 190.

Total Loss on Reacquired Debt shall equal Eversource's expenses as recorded in FERC Account 189.

Total Municipal Tax Expense shall equal Eversource's expenses as recorded in FERC Account Nos. 408.1, 409.1.

Total Plant in Service shall equal Eversource's total gross plant balance as recorded in FERC Account Nos. 301-399.

Total Transmission Depreciation Reserve shall equal Eversource's Transmission reserve balance as recorded in FERC Account 108 less the portion of such reserve for the Dispatch Center.

Transmission Merger-Related Costs shall equal Eversource's amortized merger-related transmission costs as authorized by FERC.

Transmission Operation and Maintenance Expense shall equal Eversource's expenses as recorded in FERC Account Nos. 560, 561.5 – 561.8, 562-564 and 566-576.5 and shall exclude all HQ HVDC expenses booked to accounts 560 through 576.5 and expenses already included in Transmission Support Expense, as described in Section I below, that are included in FERC Account Nos. 560-576.5.

Transmission Plant shall equal Eversource's gross plant balance as recorded in FERC Account Nos. 350-359, less Dispatch Center transmission plant.

Transmission Plant Materials and Supplies shall equal Eversource's balance as assigned to transmission, as recorded in FERC Account 154.

Transmission Related Construction Work in Progress shall equal Eversource's investment in Transmission-related projects as recorded in FERC Account 107 consistent with commission orders.

II. Calculation of Transmission Revenue Requirements

The Transmission Revenue Requirement shall equal the sum of Eversource's (A) Return and Associated Income Taxes, (B) Transmission Depreciation Expense, (C) Transmission Related Amortization of Loss on Reacquired Debt, (D) Transmission Related Amortization of Investment Tax Credits, (E) Transmission Related Municipal Tax Expense, (F) Transmission Related Payroll Tax Expense, (G) Transmission Operation and Maintenance Expense, (H) Transmission Related Administrative and General Expense (I) Transmission Support Expense, and(J) Transmission Related Taxes and Fees Charge.

A. Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate.

1. Transmission Investment Base

The Transmission Investment Base will be the average balances of (a) Transmission Plant, plus (b) Transmission Related General Plant, plus (c) Transmission Plant Held for Future Use, plus (d) Transmission Related Construction Work in Progress, less (e) Transmission Related Depreciation Reserve, less (f) Transmission Related Accumulated Deferred Taxes, plus (g) Transmission Related Loss on Reacquired Debt, plus (h) Other Regulatory Assets/Liabilities, less (i) AFUDC Regulatory Liability, plus (j) Transmission Prepayments, plus (k) Transmission Materials and Supplies, plus (l) Transmission Related Cash Working Capital.

(a) Transmission Plant will equal the balance of Eversource's investment in Transmission Plant.

(b) Transmission Related General Plant shall equal Eversource's balance of investment in General Plant multiplied by the Transmission Wages and Salaries Allocation Factor.

(c) Transmission Plant Held for Future Use shall equal the balance of Transmission Plant Held for Future Use.

(d) Transmission Related Construction Work in Progress shall equal the portion of Eversource's investment in Transmission-related projects as recorded in FERC Account 107 consistent with Commission orders.

(e) Transmission Related Depreciation Reserve shall equal the balance of Total Transmission Depreciation Reserve, plus the balance of Transmission Related General Plant Depreciation Reserve. Transmission Related General Plant Depreciation Reserve shall equal the product of General Plant Depreciation Reserve and the Transmission Wages and Salaries Allocation Factor.

(f) Transmission Accumulated Deferred Taxes shall equal Eversource's electric balance of Total Accumulated Deferred Income Taxes multiplied by the Plant Allocation Factor, less the transmission and general plant components of Dispatch Center Accumulated Deferred Income Taxes.

(g) Transmission Related Loss on Reacquired Debt shall equal Eversource's electric balance of Total Loss on Reacquired Debt multiplied by the Plant Allocation Factor.

(h) Other Regulatory Assets/Liabilities shall equal Eversource's electric balance of any deferred rate recovery of FAS 106 expense multiplied by the Transmission Wages and Salaries Allocation Factor, plus Eversource's electric balance of FAS 109 multiplied by the Plant Allocation Factor, plus Eversource's unamortized balance of merger-related transmission costs recorded in FERC Account No. 182.3 as authorized by FERC.

(i) AFUDC Regulatory Liability shall equal the unamortized balance of the capitalized AFUDC booked on Eversource's transmission projects as recorded in FERC Account 254 consistent with Commission orders.

(j) Transmission Prepayments shall equal Eversource's electric balance of Prepayments multiplied by the Transmission Wages and Salaries Allocation Factor.

(k) Transmission Materials and Supplies shall equal Eversource's electric balance of Transmission Plant Materials and Supplies.

(l) Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Transmission Operation and Maintenance Expense and Transmission Related Administrative and General Expense.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) Eversource's Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon the capital structure at the end of each year and will equal the sum of:

(i) the long term debt component, which equals the product of the actual weighted average embedded cost to maturity of Eversource's long-term debt then outstanding and the ratio that long-term debt is to Eversource's total capital.

(ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of Eversource's preferred stock then outstanding and the ratio that preferred stock is to Eversource's total capital.

(iii) the return on equity component, shall equal the product of Eversource's return on equity ("ROE") of 10.57% and the ratio that common equity is to Eversource's total capital.

(b) Federal Income Tax shall equal

[(A+[(C+B)/D]x (FT)] divided by (1-FT)

where FT is the Federal Income Tax Rate and A is the sum of the preferred stock component and the return on equity component, as determined in Sections II.A.2.(a)(ii) and (iii) above, B is Transmission Related Amortization of Investment Tax Credits, as determined in Section II.D., below, C is the Equity AFUDC component of Transmission Depreciation Expense, as defined in Section II.B., and D is Transmission Investment Base, as Determined in II.A.1., above.

(c) State Income Tax shall equal

[A+[(C+B)/D] + Federal Income Tax)x(ST)] divided by (1-ST)

where ST is the State Income Tax Rate, A is the sum of the preferred stock component and return on equity component determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section II.D. below, C is the equity AFUDC component of Transmission Depreciation Expense, as defined in Section II.B., D is the Transmission Investment Base, as determined in II.A.1., above and Federal Income Tax is the rate determined in Section II.A.2.(b) above.

B. Transmission Depreciation Expense shall equal the sum of Depreciation Expense for Transmission Plant, plus an allocation of General Plant Deprecation Expense calculated by multiplying General Plant Depreciation Expense by the Transmission Wages and Salaries Allocation Factor, less the amortization of AFUDC Regulatory Credit as recorded in Account 407.4, less the transmission plant and general plant components of Dispatch Center Depreciation Expense.

C. Transmission Related Amortization of Loss on Reacquired Debt shall equal Eversource's electric Amortization of Loss on Reacquired Debt multiplied by the Plant Allocation Factor.

D. Transmission Related Amortization of Investment Tax Credits shall equal Eversource's electric Amortization of Investment Tax Credits multiplied by the Plant Allocation Factor less the transmission plant and general plant components of Dispatch Center Amortization of Investment Tax Credits.

E. Transmission Related Municipal Tax Expense shall equal Eversource's electric Total Municipal Tax Expense multiplied by the Plant Allocation Factor, less the transmission plant and general plant components of Dispatch Center Municipal Tax Expense.

F. Transmission Related Payroll Tax Expense shall equal Eversource's electric Payroll Tax expense, multiplied by the Transmission Wages and Salaries Allocation Factor.

G. Transmission Operation and Maintenance Expense shall equal Transmission Operation and Maintenance Expenses.

H. Transmission Related Administrative and General Expenses shall equal the sum of (1) Eversource's Administrative and General Expenses multiplied by the Transmission Wages and Salaries

Allocation Factor, (2) Property Insurance multiplied by the Transmission Plant Allocation Factor, (3) Expenses included in Account 928 (excluding Merger-Related Costs included in Account 928) related to FERC Assessments multiplied by the Plant Allocation Factor, plus any other Federal and State transmission related expenses or assessments in Account 928 plus specific transmission related expenses included in Account 930.1, plus Transmission Merger-Related Costs and, (4) specific transmission related public education expenses included in Account 426.54.

I. Transmission Support Expense shall equal the expense paid by Eversource for transmission support.

J. Transmission Related Taxes and Fees Charge shall include any fee or assessment imposed by any governmental authority on service provided under this Local Service Schedule that is not specifically identified under any other section of this Local Service Schedule.

ATTACHMENT ES-I

ANNUAL LOCALIZED TRANSMISSION REVENUE REQUIREMENT

Attachment ES-I Methodology

This formula sets forth the method that Eversource will use to determine its annual total revenue requirements for each Localized Facility (“Localized Transmission Revenue Requirement”). Subsequent references in this formula to “Localized Facility” and “Localized Transmission Revenue Requirement” refer to the Localized Facility and Localized Facility Revenue Requirement for each individual Localized Transmission Project. Each Localized Facility is identified in Section 16.3.

The Localized Transmission Revenue Requirement will be calculated for an initial term for a Localized Facility commencing on the date of the New England System Operator’s Schedule 12C cost allocation determination for the Localized Facility and ending on the May 31st following the date approved by the Commission for including the costs of the Localized Facilities in this Attachment ES-I (“Initial Term”), and continuing thereafter for successive 12 month periods commencing each June 1st (“Rate Year”). The Localized Transmission Revenue Requirement for the Initial Term for a Localized Facility will be calculated based on the estimated cost of the Localized Facilities for such period, and will be charged to customers in equal monthly installments beginning on the date permitted by the Commission, and continuing through the end of the Initial Term. The Localized Transmission Revenue Requirement for the Initial Term for a Localized Facility will be trued up for the appropriate calendar year by June 30th of the succeeding year(s) based on actual costs for the Initial Term.

The Localized Transmission Revenue Requirement for a Localized Transmission Project for a Rate Year commencing after the Initial Term (and for succeeding Rate Years) will be an annual calculation based on the previous calendar year’s Localized Transmission Revenue Requirements, plus the forecasted revenue requirements of Localized Facilities to be placed in service in the upcoming Rate Year. Each June 30th,

the Localized Transmission Revenue Requirement in effect during the portion of the Rate Year that occurred in the previous calendar year will be trued-up based on actual costs from such previous calendar year.

The true-up information will be based on actual data, in lieu of allocated data if specifically identified in the FERC Form 1, or based on allocated data if such specific information is not identified. For a capital addition whose cost exceeds $20 million, Eversource will make rate base adjustments to estimates and in the true-up process to represent the estimated and actual in-service dates for the capital addition. Specifically, Eversource will adjust for transmission plant, accumulated depreciation and accumulated deferred taxes.

The Localized Transmission Revenue Requirement for Eversource that is based on data for calendar year 2004 or later shall include a Localized Incremental Return and Associated Income Taxes on Eversource's Localized PTF transmission plant investments placed in-service on or after January 1, 2004 (such investments referred to herein as "Localized Post-2003 PTF Investment"). The Localized Incremental Return and Associated Income Taxes for Localized Post-2003 Investment shall incorporate an incentive ROE adder of 100 basis points for plant investments placed in service by December 31, 2008 or as otherwise permitted in Docket Nos. ER04-157 et al. for any projects included in the Regional System Plan ("RSP"), and shall incorporate any incentive ROE adder approved by the FERC under Order No. 679 for other plant investments. The total ROE for any project, including any authorized ROE incentives for Post-2003 PTF Investment and any other incentive ROE approved by FERC under Order No. 679 shall be capped by the top of the applicable zone of reasonableness determined by FERC for the relevant period. The data used in determining Eversource's Localized Incremental Return and Associated Taxes for Localized Post-2003 Investment shall be based on actual data in lieu of allocated data if specifically identified in Eversource accounting records.

I. Definitions

Capitalized terms not otherwise defined in the Tariff and as used in this formula have the following definitions:

A. Allocation Factors

1. Localized Transmission Allocation Factor shall equal the ratio of Localized Transmission Plant in Service to total investment in Transmission Plant.

2. Total Localized Plant Allocation Factor shall equal the ratio of Localized Transmission Plant in Service to Total Plant in Service.

3. Transmission Wages and Salaries Allocation Factor shall equal the ratio of Eversource's Transmission-related direct wages and salaries, including those of affiliated companies, to Eversource's total direct wages and salaries, including those of affiliated companies, and excluding administrative and general wages and salaries.

B. Terms

Administrative and General Expense shall equal Eversource's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928 and 930.1 and excluding Merger-Related Costs included in FERC Account Nos. 920-935 (other than those in FERC Account Nos. 924, 928 and 930.1, which have already been excluded).

Amortization of Loss on Reacquired Debt shall equal Eversource's expenses as recorded in FERC Account No. 428.1.

Amortization of Investment Tax Credits shall equal Eversource's expenses as recorded in FERC Account No. 411.4.

Depreciation Expense for Localized Transmission Plant shall equal Eversource's Localized Facilities expenses as recorded in FERC Account No. 403.

Dispatch Center means CL&P's CONVEX dispatch center.

Dispatch Center Plant shall equal CL&P's gross plant balance for the Dispatch Center as recorded in FERC Account Nos. 350-359 and 389-399.

General Plant shall equal Eversource's gross plant balance as recorded in FERC Account Nos. 389-399 less Dispatch Center general plant.

General Plant Depreciation Expense shall equal Eversource's general plant expenses as recorded in FERC Account No. 403 less the portion of such expense for the Dispatch Center.

General Plant Depreciation Reserve shall equal Eversource's general plant reserve balance as recorded in FERC Account No. 108 less the portion of such reserve for the Dispatch Center.

Merger-Related Costs shall equal Eversource's amortized merger-related costs as authorized by FERC or by state regulatory order.

Other Regulatory Assets/Liabilities shall equal Eversource's unamortized balance of merger-related transmission costs recorded in FERC Account No. 182.3 as authorized by FERC.

Payroll Taxes shall equal those payroll expenses as recorded in Eversource's FERC Account Nos. 408.1 and 409.1.

Prepayments shall equal Eversource's prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal Eversource's expenses as recorded in FERC Account No. 924.

Total Accumulated Deferred Income Taxes shall equal the net of Eversource's deferred tax balance as recorded in FERC Account Nos. 281-283 and Eversource's deferred tax balance as recorded in FERC Account No. 190.

Total Loss on Reacquired Debt shall equal Eversource's expenses as recorded in FERC Account 189.

Total Municipal Tax Expense shall equal Eversource's expenses as recorded in FERC Account Nos. 408.1, 409.1.

Transmission Merger-Related Costs shall equal Eversource's amortized merger-related transmission costs as authorized by FERC.

Localized Transmission Plant in Service shall equal Eversource's Localized Facilities gross plant balance as recorded in FERC Account Nos. 350-359.

Localized Transmission Plant Held for Future Use shall equal Eversource's Localized Facilities balance as recorded in FERC Account 105.

Localized Transmission Depreciation Reserve shall equal Eversource's Localized Facilities reserve balance as recorded in FERC Account 108.

Transmission Operation and Maintenance Expense shall equal Eversource's expenses as recorded in FERC Account Nos. 560, 561.5 – 561.8, 562-564 and 566-576.5 and shall exclude all HQ HVDC expenses booked to accounts 560 through 576.5 and expenses already included in Transmission Support Expense, as described in Section I below, which are included in FERC Account Nos. 560-576.5.

Transmission Plant shall equal Eversource's gross plant balance as recorded in FERC Account Nos. 350-359.

Transmission Plant Materials and Supplies shall equal Eversource's balance as assigned to transmission, as recorded in FERC Account 154.

Total Plant in Service shall equal Eversource's total gross plant balance as recorded in FERC Account Nos. 301-399.

II. Calculation of Localized Transmission Revenue Requirements

The Localized Transmission Revenue Requirements shall equal the sum of Eversource's (A) Localized Return and Associated Income Taxes (including the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment), (B) Localized Transmission Depreciation Expense, (C) Localized

Transmission Related Amortization of Loss on Reacquired Debt, (D) Localized Transmission Related Amortization of Investment Tax Credits, (E) Localized Transmission Related Municipal Tax Expense, (F) Localized Transmission Related Payroll Tax Expense, (G) Localized Transmission Operation and Maintenance Expense, (H) Localized Transmission Related Administrative and General Expense , (I) Localized Transmission Support Expense, and (J) Localized Transmission Related Taxes and Fees Charge. The Localized Incremental Return and Associated Income Taxes for Localized Post-2003 PTF Investment for Eversource shall be calculated using the investment base components specifically identified in Section A.1 of the formula below.

A. Localized Return and Associated Income Taxes shall equal the product of the Localized Transmission Investment Base and the Cost of Capital Rate. To calculate the Localized Incremental Return and Associated Income Taxes for Localized Post-2003 PTF Investment, Localized Transmission Plant will only include Sections II.A.1.(a), (c), and (d), in the manner indicated.

1. Localized Transmission Investment Base

The Localized Transmission Investment Base will be the average balances of (a) Localized Transmission Plant, plus (b) Localized Transmission Plant Held for Future Use less (c) Localized Transmission Related Depreciation Reserve, less (d) Localized Transmission Related Accumulated Deferred Taxes, plus (e) Localized Transmission Related Loss of Reacquired Debt, plus (f) Other Regulatory Assets/Liabilities, plus (~~f~~g) Localized Transmission Prepayments, plus (~~g~~h) Localized Transmission Materials and Supplies, plus (~~h~~i) Localized Transmission Related Cash Working Capital.

(a) Localized Transmission Plant will equal the balance of (1) Eversource's investment in Localized Transmission Plant plus, (2) Eversource's balance of investment in General Plant multiplied by the Transmission Wages and Salaries Allocation Factor, further multiplied by the Localized Transmission Allocation Factor. In order to calculate the Localized Incremental Return and Associated Income Taxes for Localized Post-2003 PTF Investment, Localized Post-2003 PTF Transmission Plant shall be separately identified.

(b) Localized Transmission Plant Held for Future Use shall equal Eversource's balance of Localized Transmission Plant Held for Future Use.

(c) Localized Transmission Related Depreciation Reserve shall equal the balance of Localized Transmission Depreciation Reserve plus the balance of Localized Transmission Related General Plant Depreciation Reserve. Localized Transmission Related General Plant Depreciation Reserve shall equal the product of General Plant Depreciation Reserve and the Transmission Wages and Salaries Allocation Factor, further multiplied by the Localized Transmission Allocation Factor. In order to calculate the Localized Incremental Return and Associated Income Taxes for Localized Post-2003 PTF Investment, Localized Transmission Related Depreciation Reserve associated with Localized Post-2003 PTF Investment shall equal Eversource's balance of Localized Transmission Depreciation Reserve.

(d) Localized Transmission Related Accumulated Deferred Taxes shall equal Eversource's electric balance of Total Accumulated Deferred Income Taxes, multiplied by the Total Localized Plant Allocation Factor. To calculate the Localized Incremental Return and Associated Income Taxes for Localized Post-2003 PTF Investment, Localized Transmission Related Accumulated Deferred Taxes associated with Localized Post-2003 PTF Investment shall equal Eversource's electric balance of Total Accumulated Deferred Income Taxes multiplied by the Total Localized Plant Allocation Factor.

(e) Localized Related Loss on Reacquired Debt shall equal Eversource's electric balance of Total Loss on Reacquired Debt multiplied by the Total Localized Plant Allocation Factor.

(f) Localized Transmission Other Regulatory Assets/Liabilities shall equal Eversource's unamortized balance of merger-related transmission costs recorded in FERC Account No. 182.3 as authorized by FERC multiplied by the Localized Transmission Allocation Factor.

(~~f~~g) Localized Transmission Prepayments shall equal Eversource's electric balance of Prepayments multiplied by the Transmission Wages and Salaries Allocation Factor and further multiplied by the Localized Transmission Allocation Factor.

(~~g~~h) Localized Transmission Materials and Supplies shall equal Eversource's electric balance of Transmission Plant Materials and Supplies multiplied by the Localized Transmission Allocation Factor.

(~~h~~i) Localized Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of (i) Localized Transmission Operation and Maintenance Expense, plus (ii) Localized Administrative and General Expense.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) Eversource's Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon the average capital structure and will equal the sum of:

(i) the long term debt component, which equals the product of the actual weighted average embedded cost to maturity of Eversource's long-term debt then outstanding and the ratio that long-term debt is to Eversource's total capital.

(ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of Eversource's preferred stock then outstanding and the ratio that preferred stock is to Eversource's total capital.

(iii) the return on equity component shall equal the product of Eversource's return on equity ("ROE") of 11.07% and the ratio that common equity is to Eversource's total capital. In order to calculate the Localized Incremental Return and Associated Taxes for Post-2003 PTF Investment, the Localized Incremental Return on Equity shall be the product of (1) Eversource's incremental return on equity of 1% for transmission plant investments associated with projects included in the RSP and placed in service by December 31, 2008 or otherwise permitted in Docket Nos. ER04-157 et al., and (2) any ROE incentive adder approved by the FERC under Order No. 679 for other transmission plant investments, provided that the total ROE for any project, including any such ROE incentives, shall be capped by the top of the applicable zone of reasonableness determined by FERC for the relevant period; and (3) the ratio of that common equity to total capital.[1]

(b) Federal Income Tax shall equal

[(A+[(C+B)/D]) x (FT)] divided by (1-FT) where FT is the Federal Income Tax Rate and A is the sum of the preferred stock component and the return on equity component, as determined in Sections II.A.2.(a)(ii) and (iii) above, B is Localized Transmission Related Amortization of Investment Tax Credits, as determined in Section II.D., below, C is the Equity AFUDC component of Localized Transmission Depreciation Expense, as defined in Section II.B., and D is Localized Transmission Investment Base, as Determined in II.A.1., above.

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1 FERC Form-730 contains a list of transmission projects for which FERC has granted incentives under Order No. 679.

(c) State Income Tax Shall equal:

[(A+[(C+B)/D] + Federal Income Tax) x (ST)] divided by (1-ST)

where ST is the State Income Tax Rate, A is the sum of the preferred stock component and return on equity component determined in Sections II.A.2.(a)(ii) and (iii) above, B is the

Localized Transmission Related Amortization of Investment Tax Credits as determined in Section II.D. below, C is the equity AFUDC component of Localized Transmission Depreciation Expense, as defined in Section II.B., D is the Localized Transmission Investment Base, as determined in II.A.1. above and Federal Income Tax is the rate determined in Section II.A.2.(b) above.

B. Localized Transmission Depreciation Expense shall equal the sum of Depreciation Expense for Localized Transmission Plant, plus an allocation of General Plant Deprecation Expense calculated by multiplying General Plant Depreciation Expense by the Transmission Wages and Salaries Allocation Factor and further multiplied by the Localized Transmission Allocation Factor.

C. Localized Transmission Related Amortization of Loss on Reacquired Debt shall equal Eversource's electric Amortization of Loss on Reacquired Debt multiplied by the Total Localized Plant Allocation Factor.

D. Localized Transmission Related Amortization of Investment Tax Credits shall equal Eversource's electric Amortization of Investment Tax Credits multiplied by the Total Localized Plant Allocation Factor.

E. Localized Transmission Related Municipal Tax Expense shall equal Eversource's Total Municipal Tax Expense multiplied by the Total Localized Plant Allocation Factor.

F. Localized Transmission Related Payroll Tax Expense shall equal Eversource's electric Payroll Taxes expense, multiplied by the Transmission Wages and Salaries Allocation Factor, and further multiplied by the Localized Transmission Allocation Factor.

G. <u>Localized Transmission Operation and Maintenance Expense</u> shall equal Eversource's Transmission Operation and Maintenance Expense multiplied by the Localized Transmission Allocation Factor.

H. <u>Localized Transmission Related Administrative and General Expense</u> shall equal the sum of (1) Eversource's Administrative and General Expense multiplied by the Transmission Wages and Salaries Allocation Factor and further multiplied by the Localized Transmission Allocation Factor, (2) Property Insurance multiplied by the Total Localized Plant Allocation Factor, (3) Expenses included in Account 928 <u>(excluding Merger-Related Costs included in Account 928)</u> related to FERC Assessments multiplied by the Total Localized Plant Allocation Factor, (4) Federal and State transmission related expenses or assessments in Account 928 multiplied by the Localized Transmission Allocation Factor, (5) specific transmission related expenses included in Account No. 930.1, multiplied by the Localized Transmission Allocation Factor, <u>plus Transmission Merger-Related Costs multiplied by the Localized Transmission Allocation Factor</u> and (6) specific Localized Facility related public education expenses included in Account 426.54.

I. <u>Transmission Support Expense</u> shall equal the expense paid by Eversource for transmission support for Localized Facilities.

J. <u>Transmission Related Taxes and Fees Charge</u> shall include any fee or assessment imposed by any governmental authority on transmission service provided under this Local Service Schedule that is not specifically identified under any other section of this Local Service Schedule, multiplied by the Localized Transmission Allocation Factor.

SCHEDULE 21-ES

ATTACHMENT ES-L

Creditworthiness Procedures

1. **General Information**

All customers taking any service under Schedule 21-ES, the Local Service Schedule ("LSS"), and the associated schedules of The Connecticut Light and Power Company, Western Massachusetts Electric Company, and Public Service Company of New Hampshire ("Eversource") must meet the terms of this Attachment ES-L.

2. **Establishing Creditworthiness**

a) Each customer's creditworthiness must be established before receiving transmission services from Eversource. A customer will be evaluated at the time that its application for transmission service is provided to Eversource based on the creditworthiness information required under this Attachment ES-L. Eversource shall conduct a credit review of each Transmission Customer not less than annually or upon reasonable request by the Transmission Customer.

b) Eversource will review the customer's creditworthiness information for completeness and will notify the customer if additional information is required.

c) Upon completion of a creditworthiness evaluation of a customer, Eversource will forward a written evaluation to the customer if they determine that Financial Assurance must be provided.

3. Financial Information

Customers requesting transmission service must submit if available the following:

a) All current rating agency reports of the customer from Standard and Poor's ("S&P"), Moody's Investors Service ("Moody's"), and/or Fitch Ratings ("Fitch").

b) A Management Discussion and Analysis ("MD&A") along with audited financial statements provided by an independent registered public accounting firm or a registered

independent auditor for the three (3) most recent fiscal years, or the period of the customer's existence, if shorter than three (3) years.

4. Creditworthiness – Qualification for Unsecured Credit

a) A customer may receive unsecured credit from Eversource equivalent to three (3) months of the transmission charges. The customer must meet at least one of the following criteria:

(i) If rated, the customer's lowest rating from the three rating agencies on its senior unsecured long-term debt; or if the customer does not have such a rating, then one rating level below the rating then assigned to the customer's corporate credit rating, as follows:

1. a Standard and Poor's or Fitch rating of at least BBB, or

2. a Moody's rating of least Baa2.

(ii) If un-rated or if rated below BBB/Baa2, as described in 4(a)(i) above, the customer must meet all of the following creditworthiness criteria for the three (3) most recent fiscal years:

1. A Capitalization Ratio (Debt divided by the sum of shareholders' equity and Debt) of no more than 60 percent Debt, where "Debt" is defined as the sum of all long-term and short-term debt, preferred securities and capital leases. Each of which is recorded in accordance with generally accepted accounting principles;

2. Earnings before interest, taxes, depreciation and amortization ("EBITDA") in the most recent fiscal quarter divided by interest expense (ratio of EBITDA-to-interest expense of at least three (3) times); and

3. Audited Financial Statements with an unqualified auditor opinion.

b) If the customer relies on the creditworthiness of a parent company, the parent company must satisfy the ratings criteria in Section 4(a) above, and must provide to Eversource a written

guarantee that it will be unconditionally responsible for all financial obligations associated with the customer's receipt of transmission service from Eversource.

c) If the customer or the customer's parent company do not qualify for unsecured credit under Sections 4(a) or (b) above, the customer can still qualify for unsecured credit equivalent to three (3) months of transmission service charges, if:

(i) the customer has, on a rolling basis, 12 consecutive months of payments to Eversource with no missed, late or defaults in payment; or

(ii) the customer has an executed long-term contract for the sale of the full output (energy and capacity) of its generating unit and either has executed a corresponding service transmission service agreement under Schedule 21-ES for the transmission of that output or the execution of such agreement is pending the customer's demonstration of creditworthiness.

5. Financial Assurance

If the customer does not meet the applicable requirements for unsecured credit set out in Section 4 then the customer must either:

a) pay in advance an amount equal to the lesser of the total charge for transmission service not less than five (5) days in advance of the commencement of service, in which case Eversource will pay to the customer interest on the amounts not yet due to Eversource, computed in accordance with 18 C.F.R. §35.19(a)(2)(iii) of the Commission's Regulations; or

b) obtain Financial Assurance in the form of a letter of credit or a parent guarantee equal to the equivalent of three (3) months of transmission service charges prior to receiving service.

(i) The letter of credit must be one or more irrevocable, transferable standby letters of credit issued by a United States commercial bank or a United States branch of a foreign bank provided that such customer is not an affiliate of such bank. The issuing bank must have a credit rating of at least A2 from Moody's or an A rating from S&P or Fitch, or an equivalent credit rating by another nationally recognized rating service reasonably acceptable to Eversource, provided that such bank shall have assets totaling not less than

ten billion dollars ($10,000,000,000). All costs of the letter of credit shall be borne by the applicant for such letter of credit. In the event of an inconsistency in the ratings by Moody's, S&P, or Fitch, a "split rating", the lowest credit rating shall apply.

(ii) If the credit rating of a bank or other financial institution issuing a letter of credit to a customer falls below the levels specified in Section 5(b)(i) above, the customer shall have three (3) business days to obtain a suitable letter of credit from another bank or other financial institution that meets the specified levels unless Eversource agrees in writing to extend such period.

6. Notifications

Each customer must inform Eversource in writing within three (3) business days of any material change in its or its letter of credit issuer's financial condition, and if the customer qualifies under Section 4(b), that of its parent company. A material change in financial condition may include, without limitation, the following:

a) change in ownership by way of a merger, acquisition, or substantial sale of assets;
b) downgrade by a recognized major financial rating agency;
c) placement on credit watch with negative implications by a major financial rating agency;
d) a bankruptcy filing by the customer or parent;
e) any action requiring the filing of a SEC Form 8-K;
f) declaration of or acknowledgement of insolvency;
g) report of a significant quarterly loss or decline in earnings;
h) resignation of key officer(s); or
i) issuance of a regulatory order and/or the filing of a lawsuit that could materially adversely impact current or future financial results.

7. Ongoing Financial Review

Each customer is required to submit to Eversource annually or when issued, as applicable:

a) current rating agency reports;
b) audited financial statements from an independent registered public accounting firm or a registered independent auditor; and
c) SEC Forms 10-K and 8-K, promptly upon their filing.

8. Change in Creditworthiness Status

A customer who has been extended unsecured credit pursuant to Section 4, must comply with the terms of Financial Assurance in Section 5, if one or more of the following conditions apply:

a) the customer no longer meets the applicable criteria for unsecured credit in Section 4;

b) the customer exceeds the amount of unsecured credit extended by Eversource, in which case Financial Assurance equal to the amount of exceeded unsecured credit must be provided within five (5) business days; or

c) the customer has missed two or more payments for any of the transmission services provided by Eversource in the last twelve (12) months.

9. Procedures for Changes in Credit Levels and Collateral Requirements

a) Eversource shall issue notice to a customer of any changes to the approved credit levels and/or collateral requirements within five (5) business days after (1) receiving notification of any material changes in financial condition under Section 6 above; (2) receiving the information required for the customer's ongoing financial review listed in Section 7 above; or (3) the occurrence of any of the events leading to a change in creditworthiness requirements listed in Section 8 above.

b) A customer may submit a written request that Eversource provide an explanation of the reasons for the changes in credit levels and/or collateral requirements within five (5) business days after receiving notification of the changes. Eversource will provide a written response within five (5) business days after receiving such a request.

10. Contesting Creditworthiness Determinations

A customer may contest Eversource's determination of its creditworthiness by submitting a written request for re-evaluation within 20 calendar days of being notified of the creditworthiness determination. The request should provide information supporting the basis for a re-evaluation of the customer's creditworthiness. Eversource will review the request and respond within 20 calendar days of receipt.

11. Process for Changing Credit Requirements

a) In the event Eversource plans to revise the Schedule 21-ES requirements for credit levels or collateral requirements described in this Attachment ES-L, they will make a filing under Section 205 of the Federal Power Act.

b) Eversource shall provide written notification to ISO-NE and stakeholders of any filing described above, at least 30 days in advance of such filing.

c) Filing notifications shall include a detailed description of the filing, including a redlined document containing revised changes(s) to this Attachment ES-L.

d) Eversource shall consult with interested stakeholders upon request.

e) Following Commission acceptance of such filing and upon the effective date, Eversource shall revise its Attachment ES-L an updated version of Schedule 21-ES shall be posed to the ISO-NE web site.

f) When Eversource changes its credit requirements for service under Schedule 21-ES, the customer is responsible for forwarding updated financial information to Eversource. The customer must indicate whether the change affects its ability to meet the requirements of Attachment ES-L. In cases where the customer's credit status has changed, the customer must take the necessary steps to comply with the revised credit requirements of Attachment ES-L by the effective date of the change.

12. Suspension of Service

Eversource may immediately suspend service (with notification to the Commission) to a customer, and may initiate proceedings with the Commission to terminate service, if the customer does not meet the terms described in Sections 4 through 8 at any time during the term of service or if the customer's payment obligations to Eversource exceed the amount of unsecured or secured credit to which it is entitled under this Attachment ES-L. A customer is not obligated to pay for transmission service that is not provided as a result of a suspension of service.