AFFIDAVIT OF ROBERT M. FAGAN

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Power Providers Group	
v.	Docket No. EL11-20-000
PJM Interconnection, L.L.C.	
PJM Interconnection, L.L.C.	Docket No. ER11-2875-000
	(not consolidated)

AFFIDAVIT OF ROBERT M. FAGAN

ON THE BEHALF OF THE

NEW JERSEY DIVISION OF RATE COUNSEL

I. Introduction and Summary

1. My name is Robert M. Fagan. I am a Senior Associate at Synapse Energy Economics, an energy consulting firm in Cambridge, Massachusetts. My professional experience is focused on various technical, economic and regulatory issues in the energy utility industry. I am an energy economics analyst and mechanical engineer with over 20 years of experience in the energy industry. My work has focused primarily on electric power industry issues, especially economic and technical analysis of competitive electricity markets development, electric power transmission pricing structures, assessment and implementation of demand-side resource alternatives, and assessment of different aspects of utility-scale wind power. I hold an M.A. from Boston University in Energy and Environmental Studies and a B.S. from Clarkson University in Mechanical Engineering. I have testified before numerous State utility regulatory commissions, Canadian Provincial regulatory authorities, and the FERC on various electric utility policy issues. My resume is included as Attachment 1 to this affidavit.

2. I have been asked by the New Jersey Division of Rate Counsel ("Rate Counsel") to summarize electric power reliability concerns in New Jersey, to document the status of electric power generation capacity in the state of New Jersey, and to describe current electric power procurement policies in the state and how they relate to PJM's wholesale electric power capacity construct, known as the Reliability Pricing Model ("RPM").

3. Based on the information contained in this affidavit, I conclude that the combination of PJM generation retirement concerns; transmission system planning concerns; existing, currently-planned and potential future exports to New York; and limited new unit generation construction arising from PJM's RPM construct illustrates that New Jersey policies to promote baseload and mid-merit generation investment through long-term contracts is a logical and sensible response to the state of the electric system in New Jersey and eastern PJM.

Background of New Jersey's System

4. The Electric Discount and Energy Competition Act of 1999 ("EDECA" or "Act"), N.J.S.A. 48:3-49 et seq., deregulated the New Jersey's electric industry. Since 1999, the four New Jersey Electric Distribution Companies (EDCs), Public Service Gas & Electric Company ("PSE&G"), Atlantic City Electric Company ("ACE"), Jersey Central Power & Light Company ("JCP&L"), and Rockland Electric Company ("RECO") (collectively, the "EDCs") have divested themselves from almost all of their generation assets. Since 2002, the EDCs have procured several billion dollars of electric supply on a yearly basis to serve their Basic Generation Service ("BGS") customers who are not served by a third party supplier or competitive retailer through a statewide auction process called the BGS Auction. The BGS Auction consists of two auctions that are held concurrently, one for larger customers on an hourly price plan ("BGS-CIEP") for a one year term and one for smaller commercial and residential customers on a fixed-price plan ("BGS-FP") laddered for one third of the load every year for a three year term. BGS CIEP and BGS-FP procurement is done in February, roughly four months prior to the commencement of the period in which winning BGS suppliers hold the load serving entities obligation for New

Jersey customers. A large portion of the State's load is purchased through the BGS Auction.

5. Because the BGS procurement auction has not been held for the 2014/2015 PJM planning year (i.e., for June 1, 2014 through May 31, 2015, also known as the 2015 Energy Year for New Jersey load suppliers) the entities that would supply this load, and take on the load serving entity obligation in the PJM marketplace for this period are unknown. Thus, at least for all but third-party supplied load (and perhaps for some of this load as well) the direct counterparty[1] that might be willing to consider self-supply arrangements under PJM RPM auction rules for the next PJM Base Residual Auction ("BRA")(in May of 2011 for PJM planning year 2014/2015) does not exist. In other words, there is no provider with an obligation to serve most[2] of New Jersey's load beyond May 2014, so there is no private party that could enter into a long-term capacity contract without incurring an unacceptable level of risk.

6. The risk of having no private entity willing or able to enter into long-term capacity contracts was forseen in the development of the RPM market design; specifically for this reason, states retained the right to act as a counterparty themselves, to order needed capacity to be built and to be treated as self-supply in PJM's BRA. This recognition of state-level procurement arrangements has implications for the manner in which self-supply of any type could be arranged under current procurement practices.

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[1] In this instance, the direct counterparty would be the buyer of power or the load serving entity, considering a purchase from the other counterparty, the generation seller. The buyer is "self" supplying by contracting with a generation seller.

[2] BGS load in New Jersey recently has ranged from roughly 72% (2009) to as much as 80% (2006) of total retail load. Data available at http://www.bgs-auction.com/bgs.dataroom.asp.

7. New Jersey procures solar capacity resources using long-term contracting approaches and those resources clear in the PJM RPM BRA. New Jersey is in the process of structuring forms of long-term contracting arrangements for offshore wind power, and it is anticipated that the capacity value associated with such wind generation would be offered, and would clear, in the PJM RPM auctions.

8. All of New Jersey is contained within the Eastern MAAC local deliverability area ("LDA") of PJM. EMAAC is a relatively dense load region within PJM that has continually exhibited relatively high energy and capacity prices, and along with New Jersey utility service territories of PSE&G and JCP&L, is a "load deliverability" region of concern for PJM's transmission planners.[3] The forecast peak load for EMAAC as published by PJM for the 2014/15 period is 33,678 MW.[4] Within the EMAAC LDA, two nested New Jersey LDAs exist – known as PS (Public Service Electric and Gas) and PS NORTH (the northern region of PS). The fact that these nested areas have been designated as LDAs by PJM does not necessarily mean that they will be constrained in every PJM RPM BRA; however, the PS North region has been binding in some of the RPM auctions, leading to significantly higher capacity prices than in the PJM region as a whole. The resulting BRA capacity clearing prices for PJM as a whole and for each of these LDAs are shown in Figure 1 below.

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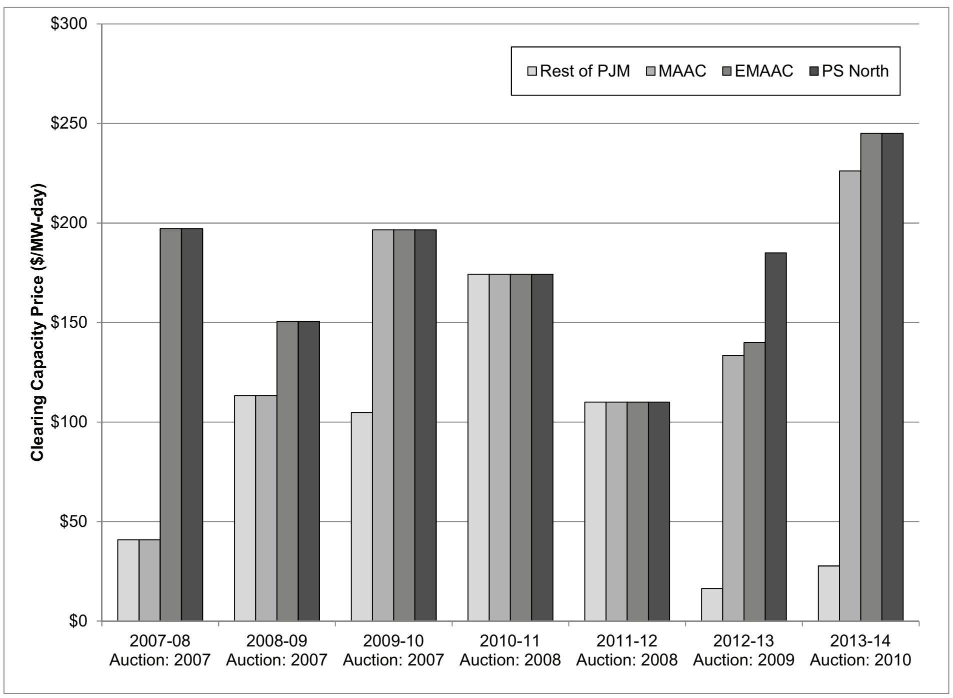
[3] In PJM-sponsored testimony in support of the proposed Susquehanna-Roseland 500 kV transmission line into northern New Jersey, PJM had forecasted reliability violations based on requirements to deliver to load in the PSE&G and JCP&L service territory and Eastern MAAC regions.

[4] 2014/15 Planning Period Parameters, available at http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/rpm-bra-planning-parameters-2014-2015.ashx.

9. Figures 1 below shows average PJM capacity prices for MACC, EMAAC, and PS North region and for the rest of PJM. PJM wholesale capacity costs are highest in the eastern PJM regions including New Jersey.

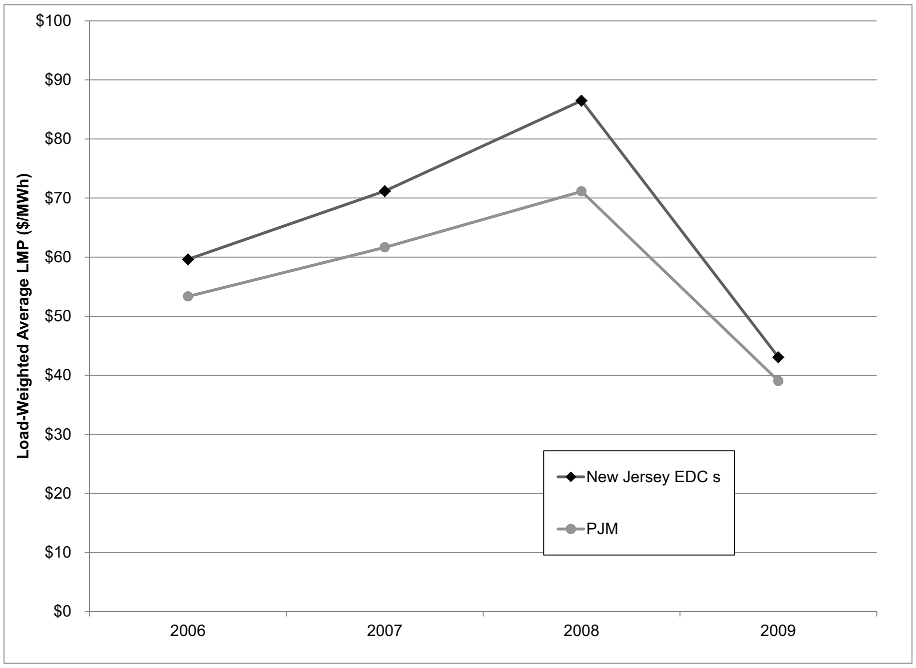
Figures 1 and 2 illustrate the relatively high electricity prices in the New Jersey EDCs, in comparison to prices in the PJM RTO as a whole.

Figure 1. PJM Base Residual Auction Clearing Prices Since Inception of RPM



Source: PJM RPM auction clearing prices, compilation by Synapse.

Figure 2 PJM Average Annual Load Weighted Energy Prices – NJ EDC Zones, PJM



Source: PJM State of the Market Report, 2006-2009 compilation by Synapse.

10. NJ currently relies on imports from more western PJM regions. PJM reported that New Jersey imports comprised 27% of its energy consumption in 2009.[5] New Jersey is currently reliant on out-of-state imports to meet reliability requirements. PJM has reported that up to 11,000 MW of coal-fired power plants are at risk of retirement.[6]

11. Recently completed merchant transmission lines with a firm transfer capacity of almost 1,000 MW significantly increase the export of power from New Jersey to New

[5] PJM Presentation to NJ BPU, June 24, 2010, slide 18. (http://www.bpu.state.nj.us/bpu/pdf/energy/HERLING%20AND%20KORMOS.pdf)

[6] PJM comments to NJ BPU, following the June 24, 2010 technical conference, page 8: "Mr. Kormos also noted that there are between 10,000 MW and 11,000 MW of coal resources in the PJM region, including New Jersey, which may be at risk for retiring due to an inability to recover their fixed, avoidable costs, according to analysis performed by the PJM Independent Market Monitor in the 2009 State of the Market Report.". (http://www.bpu.state.nj.us/bpu/pdf/energy/PJM_comments.pdf)

York.[7] Another New York merchant transmission project (660 MW) is planned for operation in 2013.[8] Additional merchant projects for further export from New Jersey to New York are discussed in the PJM RTEP report.[9] All such exports increase the need to ensure reliability in New Jersey and eastern PJM and further support a need for increased capacity resources in the region.

II. New Jersey Electric Power System Reliability and Capacity Concerns

12. The Legislature's enactment of P.L. 2011, c. 9 the Long-Term Capacity Agreement Pilot Program Act ("LCAPP Act") followed a series of public statements and events that raised specific reliability concerns. These events included delays in the construction of new transmission and transmission upgrades, anticipated retirements of existing capacity, and the failure of RPM to encourage new capacity. The statements included PJM forecasts and statements and testimony from PJM officials.

13. In recent RTEP compilations, PJM has repeatedly warned of eastern PJM reliability concerns that can only be alleviated by increased generation resources in the region or increased transmission into the region.[10] In the sections entitled "New Jersey Overview" sections of both the 2008 RTEP and 2009 RTEP compilations, PJM expressed concern that "reliability criteria violations will continue to be identified in New Jersey and other areas of eastern Mid-Atlantic PJM where similar conditions

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[7] The Neptune line, completed in 2007, supports the transfer of 670 MW of power to Long Island. The Linden VFT project, completed in 2010, supports the transfer of 300 MW of power to New York City.
[8] For example, the Hudson Transmission Partners project will support transfer of an additional 660 MW of power from New Jersey to New York. The project is planned for operation in 2013. (http://hudsonproject.com/project/status/).
[9] PJM RTEP 2009, p. 272.
[10] PJM 2008 RTEP, p.209-210, PJM 2009 RTEP p. 261-262 .

exist."[11] The conditions referenced include both load growth and generation retirements, as well as the failure to develop new generation and transmission solutions.

14. PJM further noted in the RTEP 2009 that:

> the absence of these [recently deactivated] units has a quantifiable impact on baseline reliability in New Jersey, compounded by forecasted summer peak load growth and sluggish new generation development. A significant number of these deactivations are clustered in Northern New Jersey. Major transmission upgrades [are] required to address baseline reliability issues driven by these deactivations together with other known baseline reliability transmission needs.[12]

15. The RTEP 2008 and RTEP 2009 New Jersey Overview sections conclude that:

> together, these [system reliability trends] collectively have a sustained negative impact [on] system reliability in New Jersey and throughout eastern Mid-Atlantic PJM. The extent to which eastern Mid-Atlantic PJM continues to rely on transfers into the area to meet load-serving needs drives the identification and timing of NERC reliability criteria violations.[13]

16. PJM does not conduct integrated resource planning and is not able to direct the construction of generation to resolve reliability concerns.[14] Therefore, to address these identified reliability concerns, PJM ordered the construction of a backbone 500 kv transmission line from Pennsylvania into northern New Jersey called the Susquehanna-Roseland line.

17. The Susquehanna-Roseland Line is a new 145 mile 500 kV transmission line and an upgrade of an existing 230 kV line from Susquehanna, Pennsylvania to Roseland,

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[11] Ibid.
[12] RTEP 2009 p. 269.
[13] RTEP 2009 p. 273; RTEP 2008 p. 222.
[14] Herling Direct Testimony, In The Matter of the Petition Of Public Service Electric And Gas Company For A Determination Pursuant To The Provisions of N.J.S.A. 40:55d-19 (Susquehanna – Roseland Transmission Line), BPU Dkt. No. EM09010035, Decision and Order (April 10, 2010) ("Susquehanna-Roseland Final Order"), p. 13. http://www.pseg.com/family/pseandg/powerline/pdf/BPUwrittenorder.pdf)

New Jersey. Total cost is estimated at approximately $1.2 billion, with the NJ portion costing approximately $750 million for its 45 miles. On October 9, 2007, PSE&G received a notice from PJM to build the NJ portion of the project.[15]

18. NJ BPU held public and evidentiary hearings on the project during 2009 and early 2010. The record from these hearings included testimony that PJM performs a five-year and a fifteen-year baseline analysis to assess compliance with reliability criteria and that there were 23 violations identified in the 2007 RTEP, showing the need for the project. The 2008 RTEP and the 2009 Retool Update confirmed there were violations occurring as early as 2012. During a February 4, 2010 supplementary hearing, Steven Herling of PJM stated that the 2010 peak load forecasts were almost identical to those in the 2009 load forecast. During the hearing, Mr. Herling noted that since 2003, 5862 MW of generation has retired and 7500 MW of generation is over 40 years old in the eastern Mid-Atlantic area of PJM.

19. At the hearings, PJM asserted the imminent need for the proposed Susquehanna-Roseland 500 kV transmission line, due to reliability concerns. The reliability of the region is at risk, according to PJM, in part because of concerns regarding generation plant retirement. Testimony from Mr. Herling of PJM illustrated the nature of concern over potential generation retirement in the eastern part of PJM:

- "Since 2003, fifty-six generators have been retired, removing 5862 MW from service. Almost 1250 MW of these generators were in the eastern Mid-Atlantic region of PJM.

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15 Susquehanna-Roseland Final Order, p. 10
http://www.pseg.com/family/pseandg/powerline/pdf/BPUwrittenorder.pdf)

- There are approximately 7500 MW of generation over 40 years old in the eastern Mid-Atlantic area of PJM.
- In the most recent base residual RPM auctions, 5211 MW of generation capacity failed to clear for the 2011/12 period and 6346 MW failed to clear for the 2012/13 period. Absent a revenue stream for installed capacity, if energy revenues are reduced these generators would have to be considered at risk for retirement. Of these uncleared MW, 50% and 28%, respectively, are in the eastern Mid-Atlantic area for the 2011/12 and 2012/13 periods.
- There are 1130 MW of older coal units in the eastern Mid-Atlantic area of PJM of a size less than 200 MW. As carbon restrictions are implemented, these resources will become at greater risk to be retired and removed from service. If energy use is significantly reduced, it will be very difficult to justify the investment required to operationally maintain these resources.
- In the one year period from June 2008 through May 2009, 102 units (3061 MW) in the eastern Mid-Atlantic region of PJM operated for less than 100 hours. 79 of these units (1848 MW) operated for less than 50 hours.

The conclusion which can easily be reached from this information is that the combination of unit age, environmental restrictions, reduced or non-existent revenue streams and limited operation put a considerable amount of generation in the eastern portion of PJM at risk for retirement."[16]

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[16] Source: Rebuttal Testimony, Mr. Steven Herling, before the NJ BPU, In The Matter of the Petition Of Public Service Electric And Gas Company For A Determination Pursuant To The Provisions of N.J.S.A. 40:55d-19 (Susquehanna – Roseland Transmission Line) BPU Dkt. No. EM09010035, pgs. 9-10, (Attachment 2 hereto).

20. In echoing Mr. Herling's opinion that the Susquehanna-Roseland upgrades are imperative, Mr. Esam A. F. Khadr, Director – Electric Delivery Planning in the Electric Delivery Department of PSE&G submitted testimony in support of the need for the construction of the transmission line. Mr. Khadr added that after his review of PJM's RTEP studies he agreed that the Project will address the reliability violations and that it will provide the best solution from reliability and planning perspective. He stated that in his opinion, there would be overloaded circuits to serve the northern New Jersey load beginning in the year 2012 if the Project is not placed into service, which would likely cause PJM and the transmission owners to implement emergency operating procedures, such as reducing transmission system voltages ("brown-outs") or implementing rolling black-outs for network transmission service customers. [17]

21. The BPU orally unanimously approved the project on February 11, 2010 and the written order was issued on April 21, 2010.

22. After receiving BPU approval, PSE&G notified PJM that the in-service date for the eastern portion of the project has been delayed by 2 years to 2014 with the in-service date for the western portion of the line delayed until 2015. The delays are due to on-going environmental permit reviews. The National Park Service ("NPS") is performing an Environmental Impact analysis as a permit is needed from the NPS for the line to cross the Delaware Water Gap National Recreation Area, the Appalachian National Scenic Trail and the Middle Delaware National Scenic and Recreational River.

[17] Susquehanna-Roseland Final Order", p. 10 (http://www.pseg.com/family/pseandg/powerline/pdf/BPUwrittenorder.pdf)

23. The delay in the construction of the Susquehanna-Roseland line magnified the concerns of PJM regarding reliability criteria violations in New Jersey. In a June 2010 letter to the New Jersey Department of Environmental Protection urging construction of a portion of the line, Mr. Herling stated "PJM identified the need for the Project to resolve a number of reliability criteria violations that are expected to occur as early as 2012 and extend out through our 15-year planning horizon." Mr. Herling stated further,

> Recognizing that the Hopatcong West Portion will likely be delayed, PJM will be developing specific operational procedures to manage the risk to the reliability of the region. These procedures will define, among other things, the circumstances under which service to customers in northern New Jersey will have to be curtailed to minimize the potential for broader service disruptions. Should the Hopatcong East portion of the line not be completed before June 1, 2012, such procedures will also need to be developed to address the reliability issues that are to be resolved by that portion of the line.[18]

24. The NJ BPU held a one-day technical conference on electric power capacity in New Jersey on June 24, 2010. At that conference, PJM presented summary information on New Jersey electric loads, generation capacity, demand response, and capacity additions in New Jersey.[19] The New Jersey Department of Environmental Protection ("NJ DEP") presented information on "Air Quality Regulation of Generating Units",

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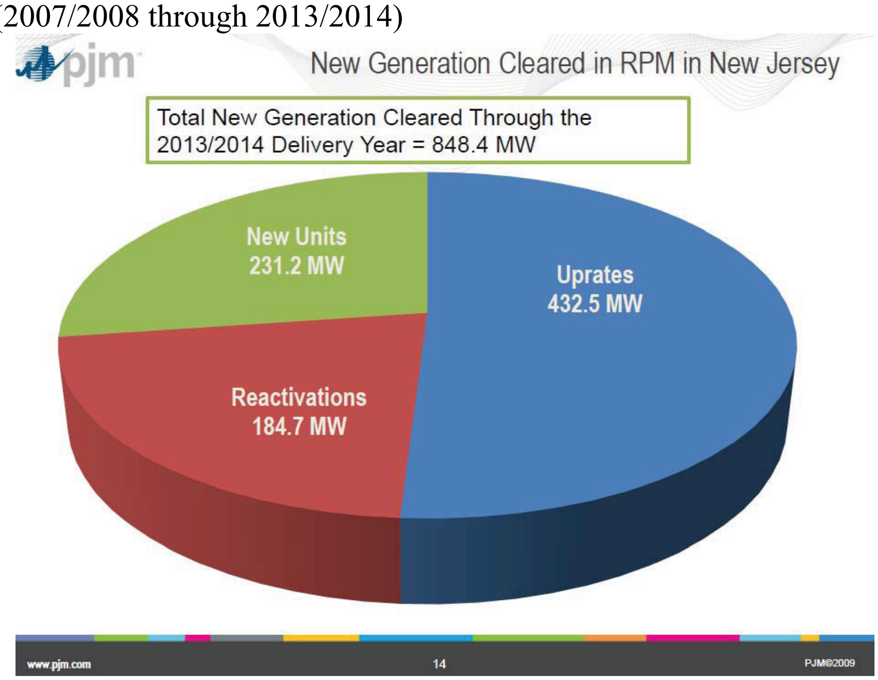
[18] June 17, 2010 letter from Steven Herling, PJM to Lou Cattuna, NJDEP (Attachment 3 hereto).

[19] Steve Herling and Mike Kormos, PJM, Presentation to New Jersey Board of Public Utilities, "New Jersey Power Supply, Load and Capacity Data", New Jersey Capacity Issues Technical Conference, June 24, 2010. (http://www.bpu.state.nj.us/bpu/pdf/energy/HERLING%20AND%20KORMOS.pdf)

including data on the quantity of generation subject to forthcoming emission regulation.[20]

25. At the technical conference, PJM presented summary information on capacity additions cleared through the first seven PJM RPM auctions held since 2007.[21] As seen in the chart below, PJM reported that a cumulative total of 231.2 MW of New Jersey, new unit capacity has cleared the PJM RPM BRA. PJM does not report exactly which units comprise that 231.2 MW. A total of 617.2 MW of "uprates" and "reactivations" in New Jersey have also cleared the RPM auctions.

Figure 3. PJM: New Jersey Capacity Cleared Through the First Seven PJM RPM Auctions (2007/2008 through 2013/2014)



Source: PJM Presentation to NJ BPU, June 24, 2010, Slide 14.

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[20] William O' Sullivan, P.E., Director, Division of Air Quality, New Jersey Department of Environmental Protection, "Air Quality Regulation of Electric Generating Units", Presentation to New Jersey Board of Public Utilities, June 24, 2010. http://www.bpu.state.nj.us/bpu/pdf/energy/OSULLIVAN%20NJDEP.pdf

[21] The first RPM Base Residual Auction was held for the planning year 2007/2008, which began June 1, 2007 and ended May 31, 2008.

26. Table 1 below summarizes the electric power capacity in New Jersey up to January 1, 2009, by commercial operation vintage, based on the latest web-posted version of PJM's EIA 411 database. Without PJM's unit-specific data on the makeup of units that cleared RPM auctions, it is not possible to map the 231.2 MW of BRA-cleared New Jersey new-unit generation to data in the PJM EIA 411 database.

Table 1. PJM EIA 411 - Electric Power Nameplate Capacity in New Jersey, by Vintage and Plant Type, January 1, 2009

Year of Commercial Operation	Combined Cycle	Combust-ion Turbine	Hydro/ Pumped Storage	Intern. Combust-ion / Other	Steam	Total
Pre-2000	2,375	3,803	464	31	8,142	14,815
2000		434				434
2001		242		4		246
2002	1,516					1,516
2003		383				383
2004						
2005						
2006						
2007						
2008						
Total	3,891	4,862	464	35	8,142	17,394

Source: PJM EIA 411 Database, data as of January 1, 2009.

27. Based on this data source[22], there have been no additional capacity installations in New Jersey since the FERC approval of RPM in 2006. However, PJM's interconnection queue does contain additional capacity recorded as "in-service" in

[22] The EIA 411 data is publicly posted on PJM's website at http://www.pjm.com/documents/reports/~/media/documents/reports/2009-pjm-eia-411-data.ashx. PJM indicated via email that the new version of the EIA 411 report would not be posted on the PJM website until June 2011.

2006, 2007 and 2008. These capacity increases are apparently at existing sites whose original commercial operation dates were earlier than 2006.

28. PJM reports New Jersey utility service territory demand response and energy efficiency peak reduction Unforced Capacity ("UCAP") cleared through the RPM auctions for the most recent auction (2013/2014 planning year) as 1,572.3 MW.[23]

29. The total peak load in New Jersey is roughly 20,000 MW[24], and existing (2010) electric power capacity in New Jersey is roughly 17,000 MW[25]. For those hours where New Jersey load is at its peak, the state's capacity needs are met with both in-state and out of state capacity resources. [26] Thus, since RPM inception and over the course of seven separate annual planning period Base Residual Auctions, new units located in New Jersey and cleared through RPM represent roughly 1.4% of the state's existing capacity (231.8/17,000) and roughly 1.2% of the state's peak load (231.8/20,000).

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[23] PJM 2013/2014 RPM Base Residual Auction Results,"Table 2B – Comparison of Demand Resources and Energy Efficiency Resources Offered versus Cleared in the 2013/14 BRA, represented in UCAP",page 7. The sum of cleared DR and EE in the four New Jersey zones AECO, JCPL, PS and RECO is 1,572.3 MW.

[24] PJM Presentation to NJ BPU, June 24, 2010, slide10. The January 2011 PJM Load Forecast Report lists 2010 normalized peak load for the four New Jersey utilities as 20,160 MW (equal to the sum of the four non-coincidental peak values for AE, JCPL, PS, and RECO, as reported on Table B-1, page 34).

[25] PJM Presentation to NJ BPU, June 24, 2010, slide9. PJM's current EIA 411 data posting (data as of January 1, 2009) indicates 17,394 MW (nameplate capacity) and 16,859 MW (summer eRPM capacity).

[26] The ability to import energy into New Jersey is reflected by the Capacity Emergency Transfer Limit (CETL) reported by PJM. This value is reported for LDAs in PJM.For example, in the 2012/2013 RPM Base Residual Auction Planning Parameters document (available at http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/2012-2013-rpm-planning-parameters.ashx) PJM reports an Eastern MAAC LDA CETL of 9,079 MW, a PS (Public Service Electric and Gas) CETL of 6,356 MW, an Atlantic Energy (AE) CETL of greater than 2,127MW, and a JCPL CETL of greater than 5,002 MW. PS, AE and JCPL are nested LDA zones within the Eastern MAAC LDA. The total import CETL for New Jersey from regions west of NJ is a subset of the Eastern MAAC CETL (Eastern MAAC also includes the Philadelphia area (PECO LDA - >2,323 MW CETL) and the Delmarva peninsula south (DPLSouthLDA - 1,746 MW CETL). PJM does not report a New Jersey CETL in the BRA Planning Parameters document.

30. The normalized summer peak load in 2000 for the four New Jersey service territories was roughly 17,785 MW.[27] 2010 summer peak normalized load in New Jersey was 20,160 MW, and PJM currently forecasts a 2020 total New Jersey utility service territory peak load of 22,494 MW.[28] PJM load forecasts are updated annually, and can change considerably from year to year. Reliability concerns are further exacerbated if actual load is greater than forecast load. From 2000 to 2010, normalized peak load growth was 2,375 MW or 13.3%. Projected summer peak growth between 2010 and 2020 is 2,332 MW, or roughly 11.6%.

31. While load continues to grow, anticipated retirements in EMAAC may reduce supply. At the June 2010 NJ BPU technical conference, the NJ Department of Environmental Protection ("NJ DEP") presented information on the existence of 7,800 MW of "High Electric Demand Day" ("HEDD") units in New Jersey. Those units consist of "low efficiency, high operation cost electric generating units used during periods of high electric demand".[29] A subset of these units are at risk of retirement due to emission regulations forthcoming over the next four to six years. Of these 7,800 MW, all are currently subject to phase I NOx restrictions, and 4,630 MW will be subject to phase

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[27] PJM Load Forecast Report, February 2001, Table B-1. JCPL normalized load for 2000 is estimated based on the GPU normalized load for 2000 and the share of GPU load for JC in 2001. RECO is estimated at 400 MW, based on a 2001 normalized load of 410 MW as reported in the PJM 2002 Load Forecast report, as RECO only joined PJM in 2002.

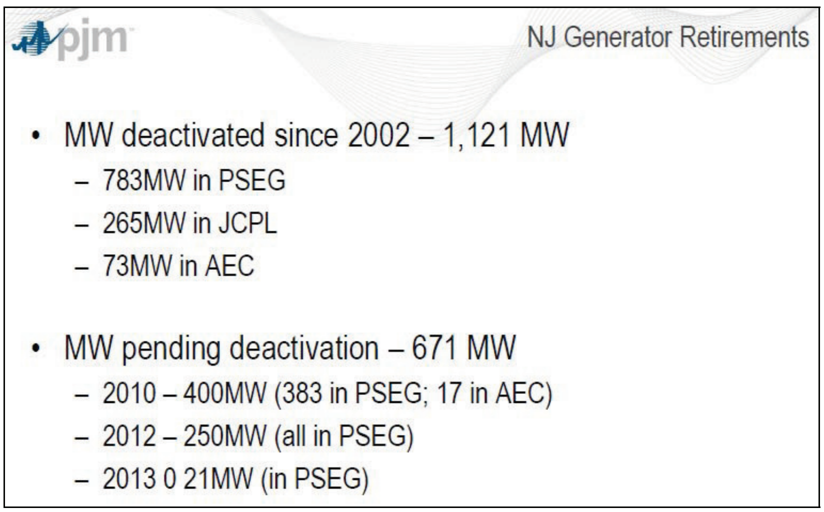
[28] PJM Load Forecast Report, January 2011, Table B-1, page 34. The total amount is based on the sum of forecast entries listed for Atlantic Electric (AE), Jersey Central Power and Light (JCPL), Public Service Electric and Gas (PS) and Rockland Electric (RECO).

[29] NJ DEP Presentation, Slide 6.(http://www.bpu.state.nj.us/bpu/pdf/energy/OSULLIVAN%20NJDEP.pdf)

II NOx emission restrictions by 2015 or 2017. Compliance options for these 4,630 MW include retirement, emission control, or placement on “emergency standby”.[30]

32. At the technical conference, PJM presented summary information on generation retirement in New Jersey. As seen in the slide below, since 2002 New Jersey has seen 1,121 MW of generation retirement. An additional 671 MW was reported as “pending deactivation.”

Figure 4. PJM: Information on New Jersey Generation Retirement



Source: PJM Presentation to the NJ BPU, June 24, 2010, slide 8

33. One of the plants likely to retire, is PSEG’s Hudson Unit #1 (454 MW nameplate) which is already running pursuant to a Reliability Must Run (“RMR”) Order. On February 24, 2005, PSEG Energy Resources & Trade LLC (“PSEG ER&T”) made a filing at FERC, ER05-644-000, requesting RMR rate treatment for five of its

[30] NJ DEP Presentation, Slide 9.(http://www.bpu.state.nj.us/bpu/pdf/energy/OSULLIVAN%20NJDEP.pdf)

generation units operated by an affiliate company, PSEG Fossil LLC ("PSEG Fossil"). One of the units included is the Hudson Unit #1 located within NJ. Based upon a deactivation study conducted by PJM which determined that PSEG ER&T should continue operation of Hudson Unit #1 for reliability purposes, the PSEG Companies sought approval for an RMR tariff for the facility. Hudson Unit #1 is a gas-fired generator that was first activated in 1964 and is considered by PSEG Fossil as "…inefficient by modern standards and currently operates at very low operating factor."[31] The original settlement was approved by FERC on Nov. 28, 2005. Presently, the Hudson Unit #1 is the only remaining facility still in operation under the original RMR tariff agreement.

34. On October 1, 2010, pursuant to the original settlement, PSEG ER&T has filed for two additional extensions of the RMR tariff for Hudson Unit #1: September 1, 2008 to September 1, 2010 and September 1, 2010 through September 1, 2011.

35. In November, 2010, PJM's Transmission Expansion Advisory Committee (TEAC) reported on its 2012 Retool Update. The TEAC reported that a reliability analysis performed without Susquehanna-Roseland resulted in eight 2010 Common Mode Outage procedure violations. The TEAC reported that incremental upgrades were not a practical substitute due to the number of violations that exceeded conductor limits.[32]

36. The TEAC also conducted a market efficiency analysis assuming that PSEG's Hudson Unit #1 remained in service in 2012 and 2013. The study found a net increase in gross congestion each year primarily in New Jersey of $160 million in

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[31] *PSEG ER&T, PSEG Fossil Informational Filing, dated Oct. 1, 2010, Affidavit of Kenneth Daledda, p. 3.* As a result of settlement negotiations, FERC granted RMR status for Hudson Unit #1 to operate until September 1, 2008 (Attachment 4 hereto).

[32] PJM TEAC November 10, 2010 powerpoint (Attachment 5 hereto).

2012 and $280 million in 2013. PJM has determined that PSEG's Hudson Unit #1 be retained on RMR through at least September 1, 2012.[33]

37. PSE&G thereafter amended its filing to extend the RMR tariff for operation of Hudson Unit #1 until September 1, 2012 based upon the additional request by PJM, in a letter dated November 11, 2010. Projected costs for reliable operation of the facility for the remainder of calendar year 2011 was estimated at $5.84 million; $52.57 million for 2012; $8.84 million for 2013; and, $2.92 million for 2014. A final determination of the RMR tariff extension is pending before FERC.

38. On June 9, 2010, Exelon Generation, LLC filed a petition with the FERC, ER10-1418-000, seeking a RMR rate schedule based on cost-of-service recovery rates pursuant to the PJM Interconnection tariff for two of their generation units located in southeastern Pennsylvania – Cromby Unit #2, Eddystone Unit #2 ("RMR Units"). These units are within the PJM Eastern MAAC LDA. Exelon submitted the petition based upon a deactivation study made by PJM that both Cromby and Eddystone were necessary for transmission reliability purposes beyond their planned deactivation deadline of May 31, 2011. Both RMR Units operate on fossil fuels, have been in operation for over 50 years and are considered by Exelon as "…uneconomic due to the combined effect of market conditions, relatively high capital and operating costs caused by their age, and environmental restrictions that would severely restrict operations or require significant capital investment."[34] Pursuant to a February 11, 2011 settlement agreement, the RMR rate schedule would become effective as of

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[33] PJM retirement summary, available at (http://www.pjm.com/planning/generation-retirements/~/media/planning/gen-retire/pending-deactivation-requests.ashx)

[34] Exelon Petition at page 2.

June 1, 2011 and continue until December 31, 2011 for the Cromby Unit and May 31, 2012 for the Eddystone Unit, respectively. A final decision is pending before the FERC.

39. These facilities currently operating pursuant to an RMR will presumably cease operation over the next several years. In addition, several other facilities serving the Eastern MAAC zone face retirement. On December 9, 2010, the New Jersey Department of Environmental Protection and Exelon Corporation entered into an Administrative Consent Order in which Exelon agreed to shut-down the 641 MW (nameplate) Oyster Creek Nuclear Generating Station by December 31, 2019.

III. New Jersey's Long-Term Capacity Agreement Pilot Program

40. Against this backdrop of delayed transmission, increasing New York exports, anticipated retirements, and limited new unit capacity, the New Jersey Legislature created a Long Term Capacity Agreement Pilot Program (LCAPP) to "ensure sufficient generation is available to the region , and thus the users in the State, in a timely and orderly manner."[35]

41. While RPM was designed in 2006 to encourage the development of new generation in such circumstances, it has not succeeded in this respect.

42. Table 2 below contains a breakdown of the 4,803 MW currently contained in the PJM generation interconnection queue for New Jersey that has either entered service, is partially in-service, or is under construction. While it may seem to indicate

[35] LCAPP legislation at P.L. 2011, C. 9, sec. 1.

considerable generation investment in New Jersey, a more careful review of the data reveals several critical points that illustrate the limited effect PJM's RPM has had on the market for development of baseload or mid-merit generation, the resources targeted by New Jersey's LCAPP policy towards ensuring a reliable supply of electricity. The additions listed as "currently under construction" have generally been limited to increases in capacity at existing sites, peaking units, solar facilities, or small units such as methane –fueled landfill gas generation facilities. The "partially in-service" additions are either solar or peaking units (or pre-RPM), and the in-service units are nuclear uprates, existing station additions, solar or landfill gas. The one baseload facility is the Linden facility addition. It went into service in 2006, and has been in the PJM interconnection queue since 1997.

43. Table 3 below summarizes the remainder of the PJM interconnection queue capacity for New Jersey, the "active" status entries. As seen, most of the capacity in that table does not have an Interconnection Service Agreement ("ISA"), the threshold used by PJM to include such capacity in its planning for reliability purposes[36]. As noted by Mr. Herling, up to 85% of the energy associated with queued generation has dropped out over the past ten years.[37] And of the 5,166 MW of NJ active status queued generation that does not have an ISA, 5,122 MW apparently has not completed a facility study, as no facility study is posted on PJM's interconnection queue page for

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[36] Susquehanna-Roseland Final Order, p. 13 (http://www.pseg.com/family/pseandg/powerline/pdf/BPUwrittenorder.pdf)

[37] Steve Herling, PJM, "The generation that is currently in the interconnection queue, there's a fairly substantial amount of that, but we have seen a very, very high dropout rate in our interconnection queue over the ten years, over 85 percent on an energy basis.". Transcript from, I/M/O the New Jersey Board of Public Utilities Review of the State's Electric and Power and Capacity Needs, BPU Dkt. No. EO09110920, (June 24, 2010), pgs.10:23 to 11:2 (Attachment 6 hereto).

this portion of "active" generation. This is a further indication of the speculative nature of much of the "active" status queued generation in New Jersey.

Table 2 PJM Queue: NJ Incremental MW – Capacity - Generation In Service, Under Construction, or Partially In-Service

		Fuel						
		Natural Gas	Nuclear	Other	Solar	Wind	All	Notes
	Status: In-Service							
Year of Commerial Operation	Pre-2006	2,344	95	8	-	-	2,447	Pre-RPM
	2006	1,188	-	-	-	-	1,188	Linden facility - Queue dates '97 & '99.
	2007	20	-	39	-	-	59	Existing station; reactivation; landfill gas.
	2008	114	236	7	-	-	357	Nuclear uprates; reactivitation ; landfill gas.
	2009	40	-	1	-	-	41	Increased capacity at existing sites.
	2010	-	-	-	1	-	1	Solar
	2011	-	-	-	3	-	3	Solar
	Subtotal	3,706	331	54	3	-	4,095	
	Status: Partially In-Service							
Year of Commerial Operation	Pre-2006	8	-	-	-	-	8	Pre-RPM
	2008	-	-	-	-	-	-	
	2009	225	-	-	-	-	225	Peakers
	2010	-	-	-	20	-	20	Solar
	Subtotal	233	-	-	20	-	253	
	Status: Under Construction							
Year of Commerial Operation	2010	-	-	-	5	-	5	Solar
	2011	-	-	5	38	-	43	Solar, landfill gas.
	2012	330	-	-	18	-	348	Peakers
	2013	60	-	-	-	-	60	Increased capacity at existing site.
	Subtotal	390	-	5	60	-	455	

Source: PJM Generation Interconnection Queue Data, Under Construction, In-Service, and Partially In-Service status, New Jersey, as of February 14, 2011.

Table 3 PJM: "Active" Status, PJM Generation Queue, New Jersey units

	MWC, Capacity			
Anticipated Year of Service	Does Not Have an ISA	Has an ISA	ISA Not Required	Total
2007	20	44	-	64
2008	63	-	15	78
2009	65	-	-	65
2010	68	-	-	68
2011	1,177	-	50	1,227
2012	1,861	-	10	1,871
2013	440	-	-	440
2014	1,428	-	-	1,428
2015	45	-	-	45
Total	5,166	44	75	5,285

Source: PJM Generation Queue Data, "Active" Status, New Jersey, as of February 14, 2011.

44. Tables 2 and 3 illustrate that New Jersey generation activity as represented by the PJM interconnection queue data consists of either 1) mostly still-speculative generation potential (Table 3), or 2) new capacity at existing stations, uprates of existing units, small facilities, solar resources with long-term contracts, and limited peaking facilities. Tables 2 and 3 illustrate that the PJM RPM mechanism has not resulted in any significant generation development activity for new baseload or mid-merit generation units.

45. The LCAPP law and the resulting structure of any contracts awarded through the NJ BPU competitive process is based on a commonly-understood "contract for differences" mechanism. In this mechanism, the selling and buying parties agree on a price – in this case, a price that is likely to hold for fifteen years – the seller then provides this capacity to the structured market. Based on the actual clearing price in the structured market (through which the product is physically delivered), the buyer and seller settle on the price difference between the contract price and the structured

market price. The procurement mechanism uses competition to obtain the "eligible"[38] electric power resource at the lowest competitive price.

46. The physical delivery of the LCAPP power is to the PJM grid. BGS and third-party suppliers then procure from the PJM grid and deliver to retail customers in New Jersey. Any settlement for differences is then completed through a non-bypassable charge that will apply to all ratepayers in New Jersey.

Observations, Conclusions, Recommendations

47. Based on the information provided by PJM and the New Jersey DEP, as noted above, reliability has been an ongoing concern in the eastern portion of PJM, and New Jersey, since at least the commencement of the RPM construct in 2006. It is reasonable to conclude that New Jersey state policy promoting the construction of new generation that can serve as a capacity resource is an entirely appropriate response to the capacity construct conditions in PJM. Actual generation retirements, potential near-term retirements, minimal new unit generation construction, recent and prospective exports to New York, and an apparently pressing need for more transmission into New Jersey (even though New Jersey is already heavily dependent on transmission for imports of power) supports a policy to construct more generation within EMAAC to ensure reliability.

48. PJM's RPM construct has produced limited new generation development in New Jersey, and even that limited development has been restricted to peaking capacity,

[38] Per the LCAPP law, an "eligible" plant must be a mid-merit or baseload power plant.

incremental onsite generation, small facilities, solar facilities, and capacity uprates at existing power plants.

49. Transmission development uncertainty (for example as reflected in the uncertain status of the Susquehanna – Roseland 500 kV transmission line) exacerbates concerns of reliability for New Jersey's electric system.

50. New Jersey's current reliance on imports to serve a significant part of its own load, coupled with recent activity that results in exports of energy to New York, contributes towards a very real need to consider means to see increased construction of electric power generation in New Jersey.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Power Providers Group	
v.	Docket No. EL11-20-000
PJM Interconnection, L.L.C.	
PJM Interconnection, L.L.C.	Docket No. ER11-2875-000
	(not consolidated)
State of Massachusetts	

I, Robert M. Fagan being duly sworn, depose and state that the contents of the foregoing Affidavit on behalf of the New Jersey Division of Rate Counsel are true, correct, accurate and complete to the best of my knowledge, information, and belief.

Robert M. Fagan

Robert M. Fagan

SUBSCRIBED AND SWORN TO before me, the undersigned Notary Public, this 4 th day of March 2011.

Notary Public

22 Pearl Street
Cambridge, MA 02139
(Address of Notary)

(SEAL)
My Commission Expires:

REBECCA ANNE KEANE
Notary Public
COMMONWEALTH OF MASSACHUSETTS
My Commission Expires
October 8, 2015

ATTACHMENT 1

Robert M. Fagan

Senior Associate
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SUMMARY

Mechanical engineer and energy economics analyst with over 25 years experience in the energy industry. Activities focused primarily on electric power industry issues, especially economic and technical analysis of transmission pricing structures, wholesale electricity markets, renewable resource alternatives and assessment and implementation of demand-side alternatives.

In-depth understanding of the complexities of, and the interrelationships between, the technical and economic dimensions of the electric power industry in the US and Canada, including the following areas of expertise:

- Wholesale energy and capacity provision under market-based and regulated structures; the extent of competitiveness of such structures.
- Potential for and operational effects of wind power integration into utility systems.
- Transmission use pricing, encompassing congestion management, losses, LMP and alternatives, financial and physical transmission rights; and transmission asset pricing (embedded cost recovery tariffs).
- Physical transmission network characteristics; related generation dispatch/system operation functions; and technical and economic attributes of generation resources.
- RTO and ISO tariff and market rules structures and operation.
- FERC regulatory policies and initiatives, including those pertaining to RTO and ISO development and evolution.
- Demand-side management, including program implementation and evaluation; and load response presence in wholesale markets.
- Building energy end-use characteristics, and energy-efficient technology options.
- Fundamentals of electric distribution systems and substation layout and operation.
- Energy modeling (spreadsheet-based, GE MAPS and online DOE-2 residential).
- State and provincial level regulatory policies and practices, including retail service and standard offer pricing structures.
- Gas industry fundamentals including regulatory and market structures, and physical infrastructure.

PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Inc., Cambridge, MA. 2004 – Present. Senior Associate
Responsibilities include consulting on issues of energy economics, analysis of electricity utility planning, operation, and regulation, including issues of transmission, generation, and demand-side management. Provide expert witness testimony on various wholesale and retail electricity industry issues. Specific project experience includes the following:

- Analysis of need for transmission facilities in Maine, Ontario, Pennsylvania, Virginia, Minnesota.
- Ongoing analysis of wholesale and retail energy and capacity market issues in New Jersey, including assessment of BGS supply alternatives and demand response options.
- Analysis of PJM transmission-related issues, including cost allocation, need for new facilities and PJM's economic modeling of new transmission effects on PJM energy market.
- Ongoing analysis of utility-sponsored energy efficiency programs in Rhode Island as part of the Rhode Island DSM Collaborative.
- Analysis of proposals in Maine for utility companies to withdraw from the ISO-NE RTO.
- Analysis of utility planning and demand-side management issues in Delaware.
- Analysis of effect of increasing the system benefits charge (SBC) in Maine to increase procurement of energy efficiency and DSM resources; analysis of impact of DSM on transmission and distribution reinforcement need.
- Evaluation of wind energy potential and economics, related transmission issues, and resource planning in Minnesota, Iowa, Indiana, and Missouri; in particular in relation to alternatives to newly proposed coal-fired power plants in MN, IA and IN.
- Analysis of need for newly proposed transmission in Pennsylvania and Ontario.
- Evaluation of wind energy "firming" premium in BC Hydro Energy Call in British Columbia.
- Evaluation of pollutant emission reduction plans and the introduction of an open access transmission tariff in Nova Scotia.
- Evaluation of the merger of Duke and Cinergy with respect to Indiana ratepayer impacts.
- Review of the termination of a Joint Generation Dispatch Agreement between sister companies of Cinergy.
- Assessment of the potential for an interstate transfer of a DSM resource between the desert southwest and California, and the transmission system impacts associated with the resource.
- Analysis of various transmission system and market power issues associated with the proposed Exelon-PSEG merger.
- Assessment of market power and transmission issues associated with the proposed use of an auction mechanism to supply standard offer power to ComEd native load customers.
- Review and analysis of the impacts of a proposed second 345 kV tie to New Brunswick from Maine on northern Maine customers.

Tabors Caramanis & Associates, Cambridge, MA 1996 -2004. Senior Associate.

- Provided expert witness testimony on transmission issues in Ontario and Alberta.

- Supported FERC-filed testimony of Dr. Tabors in numerous dockets, addressing various electric transmission and wholesale market issues.
- Analyzed transmission pricing and access policies, and electric industry restructuring proposals in US and Canadian jurisdictions including Ontario, Alberta, PJM, New York, New England, California, ERCOT, and the Midwest. Evaluated and offered alternatives for congestion management methods and wholesale electric market design.
- Attended RTO/ISO meetings, and monitored and reported on continuing developments in the New England and PJM electricity markets. Consulted on New England FTR auction and ARR allocation schemes.
- Evaluated all facets of Ontario and Alberta wholesale market development and evolution since 1997. Offered congestion management, transmission, cross-border interchange, and energy and capacity market design options. Directly participated in the Ontario Market Design Committee process. Served on the Ontario Wholesale Market Design technical panel.
- Member of TCA GE MAPS modeling team in LMP price forecasting projects.
- Assessed different aspects of the broad competitive market development themes presented in the US FERC's SMD NOPR and the application of FERC's Order 2000 on RTO development.
- Reviewed utility merger savings benchmarks, evaluated status of utility generation market power, and provided technical support underlying the analysis of competitive wholesale electricity markets in major US regions.
- Conducted life-cycle utility cost analyses for proposed new and renovated residential housing at US military bases. Compared life-cycle utility cost options for large educational and medical campuses.
- Evaluated innovative DSM competitive procurement program utilizing performance-based contracting.

Charles River Associates, Boston, MA, 1992-1996. **Associate**. Developed DSM competitive procurement RFPs and evaluation plans, and performed DSM process and impact evaluations. Conducted quantitative studies examining electric utility mergers; and examined generation capacity concentration and transmission interconnections throughout the US. Analyzed natural gas and petroleum industry economic issues; and provided regulatory testimony support to CRA staff in proceedings before the US FERC and various state utility regulatory commissions.

Rhode Islanders Saving Energy, Providence, RI, 1987-1992. **Senior Commercial/Industrial Energy Specialist**. Performed site visits, analyzed end-use energy consumption and calculated energy-efficiency improvement potential in approximately 1,000 commercial, industrial, and institutional buildings throughout Rhode Island, including assessment of lighting, HVAC, hot water, building shell, refrigeration and industrial process systems. Recommended and assisted in implementation of energy efficiency measures, and coordinated customer participation in utility DSM program efforts.

Fairchild Weston Systems, Inc., Syosset, NY 1985-1986. Facilities Engineer. Designed space renovations; managed capital improvement projects; and supervised contractors in implementation of facility upgrades.

Narragansett Electric Company, Providence RI, 1981-1984. Supervisor of Operations and Maintenance. Directed electricians in operation, maintenance, and repair of high-voltage transmission and distribution substation equipment.

EDUCATION

Boston University, M.A. Energy and Environmental Studies, 1992
Resource Economics, Ecological Economics, Econometric Modeling

Clarkson University, B.S. Mechanical Engineering, 1981
Thermal Sciences

Additional Professional Training and Academic Coursework
Utility Wind Integration Group - Short Course on Integration and Interconnection of Wind Power Plants Into Electric Power Systems (2006).
Regulatory and Legal Aspects of Electric Power Systems – Short Course – University of Texas at Austin (1998)
Illuminating Engineering Society courses in lighting design (1989).
Coursework in Solar Engineering; Building System Controls; and Cogeneration at Worcester Polytechnic Institute and Northeastern University (1984, 1988-89).
Graduate Coursework in Mechanical and Aerospace Engineering – Polytechnic Institute of New York (1985-1986)

SUMMARY OF TESTIMONY, PUBLICATIONS, AND PRESENTATIONS

TESTIMONY

New Jersey Board of Public Utilities. Oral testimony before the Board, on certain aspects of the Basic Generation Service (BGS) procurement plan for service beginning June 1, 2011. Docket No. ER10040287. Hearing conducted September, 2010.

Virginia State Corporation Commission. Pre-filed Direct Testimony filed October 23, 2009 on behalf of the Sierra Club on the need for the Potomac-Appalachian Transmission Highline (PATH), a 765 kV proposed transmission line across West Virginia, Virginia and Maryland. Proceedings are currently terminated as filing party (American Electric Power and Allegheny Power) withdrew the application pending additional RTEP analyses by PJM scheduled for 2010. Testimony addressed issues of need and modeling of DSM resources as part of the PJM RTEP planning processes.

Pennsylvania Public Utility Commission. Direct Testimony filed June 30, 2009 on behalf of the Pennsylvania Office of Consumer Advocate on the need for the Susquehanna-Roseland 500 kv proposed transmission line in portions of Luckawanna, Luzerne, Monroe, Pike, and Wayne counties. Testimony assessed the modeling for the proposed line, including load forecasts, energy efficiency resources, and demand response resources. Docket number A-2009-2082652. Surrebuttal testimony filed August 24, 2009.

Delaware Public Service Commission. Report on Behalf of the Staff of the Delaware Public Service Commission, filed in Docket No. 07-20, Delmarva's IRP docket, "Review of Delmarva Power & Light Company's Integrated Resource Plan", April 2, 2009. Jointly authored with Alice Napoleon, William Steinhurst, David White, and Kenji Takahashi of Synapse Energy Economics.

State of Maine Public Utilities Commission. Pre-filed Direct Testimony on the Application of Central Maine Power for a Certificate of Public Convenience and Necessity for the proposed Maine Power Reliability Project (MPRP), a $1.55 billion transmission enhancement project. Direct testimony focus on the non-transmission alternatives analysis conducted on behalf of CMP. Maine PUC Docket 2008-255, filed January 12, 2009 (direct) and surrebuttal (February 2, 2010) on behalf of the Maine Office of Public Advocate. Docket proceeding 2008-255, hearings completed in February 2010.

New Jersey Board of Public Utilities. Oral testimony before the Board, jointly with Bruce Biewald, on certain aspects of the Basic Generation Service (BGS) procurement plan for service beginning June 1, 2009. Docket No. ER08050310. Hearing conducted on September 29, 2008.

Wisconsin Public Service Commission. Direct and Surrebuttal Testimony in Docket 6680-CE-170 on behalf of Clean Wisconsin in the matter of an application by Wisconsin Power and Light for a CPCN for construction of a 300 MW coal plant. The testimony focused on the alternative energy options available with wind power, and the effect of the MISO RTO in helping provide capacity and energy to the Wisconsin area reliably without needed the proposed coal plant. The CPCN was denied by the WPSC in December 2008. Testimony filed in August (Direct) and September (Surrebuttal), 2008.

Ontario Energy Board. Pre-Filed Direct Testimony filed on behalf of Pollution Probe in the matter of the Examination and Critique of Demand Response and Combined Heat and Power Aspects of the Ontario Power Authority's Integrated Power System Plan and Procurement Process, Docket EB-2007-0707. The testimony addressed issues associated with the planned levels of procurement of demand response, combined heat and power, and NUG resources as part of Ontario Power Authority's long-term integrated planning process. Testimony filed on August 1, 2008. Docket is open; additional Power System Plan and Procurement filings expected from the Ontario Power Authority.

Ontario Energy Board. Direct and Supplemental Testimony filed jointly with Mr. Peter Lanzalotta on behalf of Pollution Probe in the matter of Hydro One Networks Inc. application to construct a new 500 kV transmission line between the Bruce Power complex and the town of Milton, Ontario. Docket EB-2007-0050. The testimony addressed issues of congestion (locked-in energy) modeling, need, and series compensation and generation rejection alternatives to the proposed line. Testimony filed on April 18, 2008 (Direct) and May 15, 2008 (Supplemental).

Federal Energy Regulatory Commission. Direct and Rebuttal Testimony on PJM Regional Transmission Expansion Plan (RTEP) Cost Allocation issues in Dockets ER06-456, ER06-954, ER06-1271, ER07-424, EL07-57, ER06-880, et al. The testimony addressed merchant transmission cost allocation issues. Testimony filed on behalf of the New Jersey Department of the Public Advocate, Ratepayer Division. Testimony filed on January 23, 2008 (Direct) and April 16, 2008 (Rebuttal).

Minnesota Public Utilities Commission. Supplemental Testimony and Supplemental Rebuttal Testimony on applicants' estimates of DSM savings in the Certificate of Need proceeding for the Big Stone II coal-fired power plant proposal. In the Matter of the Application by Otter Tail Power Company and Others for Certification of Transmission Facilities in Western Minnesota and In the Matter of the Application to the Minnesota Public Utilities Commission for a Route Permit for the Big Stone Transmission Project in Western Minnesota. OAH No. 12-2500-17037-2 and OAH No. 12-2500-17038-2; and MPUC Dkt. Nos. CN-05-619 and TR-05-1275. Testimony filed December 21, 2007 (Supplemental) and January 16, 2008 (Supplemental Rebuttal).

Pennsylvania Public Utility Commission. Direct testimony filed before the Commission on the effect of demand-side management on the need for a transmission line and the level of consideration of potential carbon regulation on PJM's analysis of need for the TrAIL transmission line. Docket Nos. A-110172 *et al*. Testimony filed October 31, 2007.

Iowa Public Utilities Board. Direct testimony filed before the Board on wind energy assessment in Interstate Power and Light's resource plans and its relationship to a proposed coal plant in Iowa. Docket No. GCU-07-01. Testimony filed October 21, 2007.

New Jersey Board of Public Utilities. Direct testimony before the Board on certain aspects of PSE&G's proposal to use ratepayer funding to finance a solar photovoltaic panel initiative in support of the State's solar RPS. Docket No. EO07040278. Testimony filed September 21, 2007.

Indiana Utility Regulatory Commission. Direct Testimony filed before the Commission addressing a proposed Duke – Vectren IGCC coal plant. Testimony focused on wind power potential in Indiana. Filed on behalf of the Citizens Action Coalition of Indiana, Cause No. 43114 May 14, 2007.

State of Maine Public Utilities Commission. Pre-filed testimony on the ability of DSM and distributed generation potential to reduce local supply area reinforcement needs. Testimony filed before the Commission on a Request for Certificate of Public Convenience and Necessity to Build a 115 kV Transmission Line between Saco and Old Orchard Beach. Testimony filed jointly with Peter Lanzalotta, on behalf of the Maine Public Advocate. Docket No. 2006-487, February 27, 2007.

Minnesota Public Utilities Commission. Rebuttal Testimony on wind energy potential and related transmission issues in the Certificate of Need proceeding for the Big Stone II coal-fired power plant proposal. In the Matter of the Application by Otter Tail Power Company and Others for Certification of Transmission Facilities in Western Minnesota and In the Matter of the Application to the Minnesota Public Utilities Commission for a Route Permit for the Big Stone Transmission Project in Western Minnesota. OAH No. 12-2500-17037-2 and OAH No. 12-2500-17038-2; and MPUC Dkt. Nos. CN-05-619 and TR-05-1275. December 8, 2006.

British Columbia Utilities Commission. In the Matter of BC Hydro 2006 Integrated Electricity Plan and Long Term Acquisition Plan. Pre-filed Evidence filed on behalf of the Sierra Club (BC Chapter), Sustainable Energy Association of BC, and Peace Valley Environment Association. October 6, 2006. Testimony addressing the "firming premium" associated with 2006 Call energy, liquidated damages provisions, and wind integration studies.

Maine Joint Legislative Committee on Utilities, Energy and Transportation. Testimony before the Committee in support of an Act to Encourage Energy Efficiency (LD 1931) on behalf of the Maine Natural Resources Council, February 9, 2006. The testimony and related analysis focused on the costs and benefits of increasing the system benefits charge to increase the level of energy efficiency installations by Efficiency Maine.

Nova Scotia Utilities and Review Board (UARB). Testimony filed before the UARB on behalf of the UARB staff, In The Matter of an Application by Nova Scotia Power Inc. for Approval of Air Emissions Strategy Capital Projects. Filed Jaunary 30, 2006. The testimony addressed the application for approval of installation of a flue gas desulphurization system at NSPI's Lingan station and a review of alternatives to comply with provincial emission regulations.

New Jersey Board of Public Utilities. Direct and Surrebuttal Testimony filed before the Commission addressing the Joint Petition Of Public Service Electric and Gas Company And Exelon Corporation For Approval of a Change in Control Of Public Service Electric and Gas Company And Related Authorizations (the proposed merger), BPU Docket EM05020106. Joint Testimony with Bruce Biewald and David Schlissel. Filed on behalf of the New Jersey Division of the Ratepayer Advocate, November 14, 2005 (direct) and December 27, 2005 (surrebuttal).

Indiana Utility Regulatory Commission. Direct Testimony filed before the Commission addressing the proposed Duke – Cinergy merger. Filed on behalf of the Citizens Action Coalition of Indiana, Cause No. 42873, November 8, 2005.

Illinois Commerce Commission. Direct and Rebuttal Testimony filed before the Commission addressing wholesale market aspects of Ameren's proposed competitive procurement auction (CPA). Testimony filed on behalf of the Illinois Citizens Utility Board in Dockets 05-0160, 05-0161, 05-0162. Direct Testimony filed June 15, 2005; Rebuttal Testimony filed August 10, 2005.

Illinois Commerce Commission. Direct and Rebuttal Testimony filed before the Commission addressing wholesale market aspects of Commonwealth Edison's proposed BUS (Basic Utility Service) competitive auction procurement. Testimony filed on behalf of the Illinois Citizens Utility Board and the Cook County State's Attorney's Office in Docket 05-0159. Direct Testimony filed June 8, 2005; Rebuttal Testimony filed August 3, 2005.

Indiana Utility Regulatory Commission. Responsive Testimony filed before the Commission addressing a proposed Settlement Agreement between PSI and other parties in respect of issues surrounding the Joint Generation Dispatch Agreement in place between PSI and CG&E. Filed on behalf of the Citizens Action Coalition of Indiana, Consolidated Causes No. 38707 FAC 61S1, 41954, and 42359-S1, August 31, 2005.

Indiana Utility Regulatory Commission. Direct Testimony filed before the Commission in a Fuel Adjustment Clause (FAC) Proceeding concerning the pricing aspects and merits of continuation of the Joint Generation Dispatch Agreement in place between PSI and CG&E, and related issues of PSI lost revenues from inter-company energy pricing policies. Filed on behalf of the Citizens Action Coalition of Indiana, Cause No. 38707 FAC 61S1, May 23, 2005.

Indiana Utility Regulatory Commission. Direct Testimony filed before the Commission concerning the pricing aspects and merits of continuation of the Joint Generation Dispatch Agreement in place between PSI and CG&E. Filed on behalf of the Citizens Action Coalition of Indiana, Cause No. 41954, April 21, 2005.

State of Maine Public Utilities Commission. Testimony filed before the Commission on an Analysis of Eastern Maine Electric Cooperative, Inc.'s Petition for a Finding of Public Convenience and Necessity to Purchase 15 MW of Transmission Capacity from New Brunswick Power and for Related Approvals. Testimony filed jointly with David Schlissel and Peter Lanzalotta, on behalf of the Maine Public Advocate. Docket No. 2005-17, July 19, 2005.

State of Maine Public Utilities Commission. Testimony filed before the Commission on an Analysis of Maine Public Service Company Request for a Certificate of Public Convenience and Necessity to Purchase 35 MW of Transmission Capacity from New Brunswick Power. Testimony filed jointly with David Schlissel and Peter Lanzalotta, on behalf of the Maine Public Advocate. Docket No. 2004-538 Phase II, April 14, 2005.

Nova Scotia Utilities and Review Board (UARB). Testimony filed before the UARB on behalf of the UARB staff, In The Matter of an Application by Nova Scotia Power Inc. for Approval of an Open Access Transmission Tariff (OATT). Filed April 5, 2005. The testimony addressed various aspects of OATTs and FERC's *pro forma* Order 888 OATT.

Texas Public Utilities Commission. Testimony filed before the Texas PUC in Docket No. 30485 on behalf of the Gulf Coast Coalition of Cities on CenterPoint Energy Houston Electric, LLC. Application for a Financing Order, January 7, 2005. The testimony addressed excess mitigation credits associated with CenterPoint's stranded cost recovery.

Ontario Energy Board. Testimony filed before the Ontario Energy Board, RP-2002-0120, et al., Review of the Transmission System Code (TSC) and Related Matters, Detailed Submission to the Ontario Energy Board in Response To Phase I Questions Concerning the Transmission System Code and Related Matters, October 31, 2002, on behalf of TransAlta Corporation; and Reply Comments for same, November 21, 2002. Related direct and reply filings in response to the Ontario Energy Board's "Preliminary Propositions" on TSC issues in May and June, 2003.

Alberta Energy and Utilities Board. Testimony filed before the Alberta Energy and Utilities Board, in the Matter of the Transmission Administrator's 2001 Phase I and Phase II General Rate Application, no. 2000135, pertaining to Supply Transmission Service charge proposals. Joint testimony filed with Dr. Richard D. Tabors. March 28, 2001. Testimony filed on behalf of the Alberta Buyers Coalition.

Ontario Energy Board. Testimony filed before the Ontario Energy Board, RP-1999-0044, Critique of Ontario Hydro Networks Company's Transmission Tariff Proposal and Proposal for Alternative Rate Design, January 17, 2000. Testimony filed on behalf of the Independent Power Producer's Society of Ontario.

MAJOR PROJECT WORK – BY CATEGORY

Electric Utility Industry Regulatory and Legislative Proceedings

For Pollution Probe, analysis of need for a proposed 500 kV transmission line in Ontario. (2008)

For the Iowa Office of Consumer Advocate, testimony in the case against the proposed Marshalltown coal plant expansion, addressing the ability of wind resources to help eliminate the need for the plant. (2007-2008)

For the Minnesota Center for Environmental Advocacy, preparation of expert testimony on wind energy and DSM in Minnesota and the upper Midwest in the case against the proposed Big Stone II coal plant. (2006-2008)

For the New Jersey Department of the Ratepayer advocate, ongoing analysis of myriad issues affecting New Jersey electricity consumers, including: review of BGS supply structures, participation in working group designing demand side response pilot programs, analysis of PSE&G solar PV initiatives, review of ongoing FERC proceedings on PJM transmission planning and impacts on New Jersey. (2007-2008)

For the Citizens Action Coalition of Indiana, analyzed the potential for increased wind penetration as an alternative to a proposed new coal-fired power plant. (2007)

For the Maine Office of Public Advocate, technical review of issues pertaining to potential withdrawal of Maine utilities from the ISO NE RTO. Also, technical review and expert testimony preparation on energy efficiency and demand side response resource impact on sub-transmission supply needs in the Saco Bay area. (2006-2007)

For the staff of the Nova Scotia Utility and Review Board, conducted an economic analysis of the proposed installation of flue gas desulphurization equipment by Nova Scotia Power, Inc., and alternatives to the installation, to conform to Nova Scotia provincial emission regulations. (2005-2006)

For the staff of the Nova Scotia Utility and Review Board, analyzed a proposed Open Access Transmission Tariff by Nova Scotia Power, Inc. (2005)

For the Maine Office of Public Advocate, analyzed multiple aspects of the proposed installation of a second 345 kV tie line between Maine and New Brunswick. The analyses focused on the impacts to Northern Maine electric consumers. (2005)

Electric Utility Industry Restructuring

For the Citizens Action Coalition of Indiana, analyzed the proposed merger between Duke and Cinergy, with a focus on global protections available for PSI ratepayers and the allocation of projected merger cost and savings. (2005)

For the Citizens Action Coalition of Indiana, analyzed the termination of the Joint Generation Dispatch Agreement between Cincinnati Gas and Electric and PSI with a focus on PSI ratepayer impacts. (2005)

For TransAlta Energy Corporation, developed an issues and information paper on recent Ontario and Alberta market development efforts, focusing on the likely high-level impacts associated with day-ahead and capacity market mechanisms considered in each of those regions. (2004)

For a wholesale energy market stakeholder, participate in New England and PJM RTO markets and market implementation committee meetings, review and summarize material, and advocate on behalf of client on selected market design issues. (2004) Performed similar activities for separate client in New England. (2001)

For a group of potential generation investors in Ontario, analyzed the government's proposed wholesale and retail market design changes and produced an advocacy report for submission to the Ontario Ministry of Energy. The report emphasized, among other things, the importance of retaining a competitive wholesale market structure. (2004)

For a large midwestern utility, supported multiple rounds of direct and rebuttal testimony to the US FERC by Dr. Richard Tabors on the proposed start-up of LMP markets in the Midwest ISO utility service territories. Testimony substance included PJM-MISO seams concerns, FTR allocation options, grandfathered transactions incorporation, FTR and energy market efficiency impacts, and other wholesale market and MISO transmission tariff design issues. Testimony also included quantitative analysis using GE MAPS security-constrained dispatch model runs. (2003-2004)

For the Independent Power Producers Society of Ontario, with TCA Director Seabron Adamson, developed a position paper on resource adequacy mechanisms for the Ontario electricity market. (2003)

For TransAlta Energy Corp., provided direct and reply testimony to the Ontario Energy Board on the Transmission System Code review process. Analyzed and reported on transmission "bypass" and network cost responsibility issues. (2002-2003)

For a commercial electricity marketer in Ontario, with TCA staff, analyzed Ontario market rules for interregional transactions, focusing primarily on the Michigan and New York interties, and assessed the current Ontario electricity market policy related to "failed intertie transactions". (2002)

For ESBI Alberta Ltd., then Transmission Administrator (TA) of Alberta, served as a key member of the TCA team exploring congestion management issues in the Province, and providing guidance to the TA in presenting congestion management options to Alberta stakeholders, with a particular focus on new transmission expansion pricing and cost allocation issues. (2001)

For a coalition of power producers and marketers in Alberta, filed joint expert witness testimony with Dr. Tabors on the nature of certain transmission access charges associated with supply transmission service. (2001)

For a prospective market participant, served as a core member of the project team that developed summary reports on the New York, New England and PJM wholesale electricity spot market structures. The reports focused on market structure fundamentals, historical transmission flow patterns, forecasted transmission congestion and costs, transmission availability and FTR valuation and market results. (2001)

For the ERCOT ISO, served as a key TCA team member helping to develop and assemble a set of protocols to guide the principles, operation and settlement of the forthcoming Texas competitive wholesale electricity market. (2000)

For the Independent Power Producer's Society of Ontario, served as expert witness and filed evidence with the Ontario Energy Board supporting an alternative transmission tariff design, and critiquing Ontario Hydro Networks Company's (OHNC) proposed rate structure. Also a member of OHNC's Advisory Team on net versus gross billing issues and a leading proponent of a progressive, embedded-generation-friendly tariff structure. (1999-2000)

For a large midwestern utility, designed transmission tariff and wholesale market structures consistent with the proposed establishment of an Independent Transmission Company paradigm for transmission operations. (1999-2000)

For a coalition of independent power producers and marketers in Alberta, helped develop evidence submitted by Dr. Tabors and Dr. Steven Stoft with the Alberta Energy and Utilities Board supporting an alternative to ESBI's proposed transmission tariff. The evidence critiqued the fairness and efficiency of ESBI's proposed tariff, and offered a simple alternative to deal with Alberta's near-term southern supply shortage. (1999)

For Enron Canada Corp., provided ongoing technical support and policy advice during the tenure of the Ontario Market Design Committee (MDC). Presented material on congestion pricing before the committee, and submitted technical assessments of most wholesale market development issues. (1998-1999)

Member of the Ontario Wholesale Market Design Technical Panel. The panel's responsibilities included refinement of the wholesale market design as specified by the Market Design Committee, and specification of the market's initial operating requirements. Also served on two sub-panels: bidding and scheduling; and ancillary services. (1998-1999)

For Enron Canada Corp, assessed the generation markets in Ontario and Alberta and recommended policies for maximizing competitive market mechanisms and minimizing stranded cost burdens. Authored reports on stranded costs in Ontario, and on the legislated hedges structure in Alberta. (1997 - 1998)

For an independent power producer, assessed New England markets for electricity and assisted in valuation of generation assets for sale. (1997)

In support of testimony filed by CCEM (Coalition for Competitive Electric Markets) with the FERC, assessed alternative transmission pricing and wholesale market structures proposed for the NY, NE and PJM regions. The filings proposed market mechanisms to produce competitive wholesale electric energy markets and zonal-based transmission pricing structures. (1996-1997)

Electric Utility Mergers and Market Power Analysis

For the New Jersey Ratepayer Advocate, provided jointly sponsored expert testimony (with Bruce Biewald and David Schlissel) on the potential market power effects of the proposed Exelon-PSEG merger. (2005-2006)

For the Citizens Utility Board (Illinois), provided direct and rebuttal testimony on potential market power and transmission impacts and other issues associated with ComEd's proposal to procure standard offer power through a market-based auction process. (2005)

For the Citizens Utility Board and other clients (Illinois), provided direct and rebuttal testimony on issues associated with Ameren's proposal to procure standard offer power through a market-based auction process. (2005)

In support of FERC-filed testimony by Dr. Richard Tabors, conducted a detailed examination of the accessibility of transmission service for wholesale energy market participants on the American Electric Power and Central and Southwest transmission systems. This included evaluating all transmission service requests made over the OASIS for the first six months of 1998 for the two utility systems, and a subsequent, more detailed assessment of AEP's transmission system use during all of 1998. (1998-1999)

For a US western electric utility, served as a member of the team that conducted detailed production cost modeling and strategic market assessment to determine the extent or absence of market power held by the client. (1998)

For an independent power producer, supported FERC-filed testimony on market power issues in the New York State energy and capacity markets. This included detailed supply-curve assessment of existing generation assets within the New York Power Pool. (1997)

Worked with a local economic consulting firm for a Western State public agency in conducting an analysis of the projected savings of a series of proposed electric and gas utility mergers. (1997)

For a southwestern utility company, supported CRA in conducting an analysis of the competitive effects of a proposed electric utility merger. For a northwestern utility company, analyzed the competitive effects of a proposed electric utility merger. (1995-1996)

For the Massachusetts Attorney General's Office, conducted a study of the potential for market power abuse by generators in the NEPOOL market area. (1996)

Energy Efficiency and Demand Side Management
For the United States Department of the Interior: Minerals Management Service, analyzing issues related to the integration of offshore renewable resources into the electrical grid. (2009–present)

For the Missouri Department of Natural Resources-Energy Center, Kansas City Power & Light demand-side management and integrated resource plan evaluations. (2009 – 2010)

For the Pennsylvania Office of Consumer Advocate, analysis of the ability of demand-side management efforts to reduce peak loading and affect the need for the 502 Junction – Prexy 500 kV line proposed by Allegheny Power. (2007 – 2008)

For the New Jersey Division of Rate Counsel, Department of Public Advocate, participation in demand response working group and assessment of proposal for state-sponsored demand response program. (2007)

For the Rhode Island Division of the Public Utilities Commission, ongoing technical support and participation in the statewide DSM collaborative process. (2007)

For the Maine Office of the Public Advocate, evaluated the ability of DSM and distributed generation to affect the need for transmission and distribution system reinforcement in the Saco Bay area of Central Maine Power's service territory. (2007)

For the Natural Resources Council of Maine, analyzed the costs and benefits of increasing the system benefits charge (SBC) in Maine to increase efficiency installations by Efficiency Maine. Testimony before the Maine Joint Legislative Committee on Energy and Utilities. (2006)

For Southern California Edison (SCE), working as a sub-contractor to Sargent and Lundy, analyzed the potential for an interstate transfer of a DSM resource between the desert southwest and California. For the same project, also analyzed transmission impacts of various alternatives to replace power supply from the currently closed Mohave generation station for SCE. (2005)

For two separate large New England utilities, conducted impact evaluations of large commercial and industrial sector DSM programs. (1994-1996)

For a New England utility, worked on the project team developing a set of DSM evaluation master plans for incentive-type and third-party-contracting type DSM programs (1994)

For EPRI, wrote an overview of the status of DSM information systems and the potential effects of an increasingly competitive utility environment. (1993)

For two separate large New England utilities, helped to develop competitive procurement documents (DSM RFPs) for filing before the Massachusetts Department of Public Utilities. (1993, 1994)

For a midwestern utility, conducted a trade ally study designed to determine the influence of trade allies on the market for energy efficient lighting and motor equipment. (1992-1993)

DSM Implementation
Conducted detailed site visits and suggested efficiency improvement strategies for over 1,000 commercial, industrial and institutional buildings in Rhode Island. Performed end-use energy analysis and coordinated implementation of improvements. Worked with local utility DSM program personnel to educate building owners on DSM program opportunities. (1987-1992)

Energy Modeling

For Pollution Probe, development of simplified congestion (locked-in energy) model to estimate congestion quantity effects of an alternative to a proposed new 500 kV transmission line. (2008)

For various clientele, worked closely with the TCA GE MAPS modeling group on various facets of security-constrained dispatch modeling of electric power systems across the US and Canada. Specific tasks included assisting in designing MAPS model run parameters (e.g., base case and alternative scenarios specification); proposing modeling designs to clients; supporting input data gathering; interpreting model results; and writing summary reports, memos & testimony describing the results. (2002-2004)

For a group of potential electricity supply investors in Ontario, modeled the impact of proposed generation plant phaseout trajectories on investment requirements for new supply in Ontario. (2004)

For the Independent Power Producer's Society of Ontario, conducted a retrospective quantitative analysis of the Ontario market energy and ancillary service prices during the 15 months of the new wholesale market to determine the extent of infra-marginal rents available that could have supported entry for new generation. (2003)

In support of proposals to the US Dept. of Defense for military housing privatization, performed DOE-2 model runs using an online tool; and created a spreadsheet modeling tool to analyze the efficiency and cost effectiveness of new and renovated residential construction for base housing. Performed life-cycle utility cost analysis and prepared energy plans specifying building shell, equipment and appliance efficiency measures at 15 separate Army, Navy, and Air Force installations around the nation. (2001-2003)

For the Independent Power Producer's Society of Ontario, conducted a rate impact analysis of Ontario Hydro Networks Company proposed transmission tariff. (1999-2000)

For the University of Maryland at Baltimore, conducted a life-cycle cost analysis of alternative proposals for district-type thermal energy provision, comparing existing steam delivery systems to new hot-water systems. (1998)

For the UMass Medical Center (Worcester), conducted an energy use and cost allocation analysis of a large hospital complex to assist in choosing among electric and thermal energy supply options. (2000)

For an independent power producer, developed a spreadsheet-based tool to assess the rate impact of a "clean coal" facility compared to alternative gas-fired supply options. (1996-1997)
For a private consulting firm, examined electric end-use and generation capacity information in seven industry energy models and reported the sensitivities of each model to varying levels of input aggregation. (1995)

For a private industrial firm in Virginia, developed a Monte-Carlo simulation-based spreadsheet model to solve a capital budgeting problem involving long-term choice of industrial boiler equipment. (1995)

For a New England utility, developed a spreadsheet model to help determine economic decision-making processes used by energy service companies when delivering third-party procured DSM. (1995)

Petroleum and Natural Gas Industry Analysis
For a private independent power producer, conducted an analysis of the rate impacts of the Warrior Run clean coal (fluidized bed combustion) power plant in Maryland under various assumptions of natural gas prices and environmental regulation scenarios. (1996-1997)

For a British consulting firm, researched the current status of natural gas restructuring efforts in the US and their impact on regional US power generation markets. (1996)

For a Canadian law firm representing Native Canadian interests, conducted a detailed analysis of natural gas netback pricing for Alberta gas into US Midwest and West Coast markets over a thirty-year period. (1995)

For a US natural gas pipeline consortium, performed an econometric analysis of the demand for natural gas in the state of Florida. (1992-1993)

PAPERS, PUBLICATIONS AND PRESENTATIONS

Assessing the Multiple Benefits of Clean Energy: A Resource for States, with a multi-disciplinary team of consultants. Prepared for U.S. Environmental Protection Agency, February 1, 2010.

Synapse Report and Ohio Comments in Case No. 09-09-EL-COI, "The Value of Continued Participation in RTOs", with Rick Hornby and Bruce Biewald. Prepared for Ohio Consumers' Counsel, May 26, 2009.

Review of AmerenUE February 2008 Integrated Resource Plan, with Rick Hornby, Jeff Loiter, Phil Mosenthal, Tom Franks, and David White. Prepared for Missouri Department of Natural Resources, June 18, 2008.

LMP Electricity Markets: Market Operations, Market Power, and Value for Consumers with Ezra Hausman, David White, Kenji Takahashi, and Alice Napoleon. Prepared for American Public Power Association, February 5, 2007.

Interstate Transfer of a DSM Resource: New Mexico DSM as an Alternative to Power from Mohave Generating Station. Jointly authored with Tim Woolf, Bill Steinhurst and Bruce Biewald. Presented at the 2006 ACEEE Summer Study on Energy Efficiency in Buildings and published in the proceedings. (2006)

SMD and RTO West: Where are the Benefits for Alberta? Keynote Paper prepared for the 9th Annual Conference of the Independent Power Producers Society of Alberta, with Dr. Richard D. Tabors, March 7, 2003.

A Progressive Transmission Tariff Regime: The Impact of Net Billing, presentation at the Independent Power Producer Society of Ontario annual conference, November 1999.

Tariff Structure for an Independent Transmission Company, with Richard D. Tabors, Assef Zobian, Narasimha Rao, and Rick Hornby, TCA Working Paper 101-1099-0241, November 1999.

Transmission Congestion Pricing Within and Around Ontario, presentation at the Canadian Transmission Restructuring Infocast Conference, Toronto, June 2-4, 1999.
The Restructured Ontario Electricity Generation Market and Stranded Costs. An internal company report presented to the Ontario Ministry of Energy and Environment on behalf of Enron Capital and Trade Resources Canada Corp., February 1998.

Alberta Legislated Hedges Briefing Note. An internal company report presented to the Alberta Department of Energy on behalf of Enron Capital and Trade Resources Canada, January 1998.

Generation Market Power in New England: Overall and on the Margin. Presentation at Infocast Conference: New Developments in Northeast and Mid-Atlantic Wholesale Power Markets, Boston, June 1997.

The Market for Power in New England: The Competitive Implications of Restructuring. Prepared for the Office of the Attorney General, Commonwealth of Massachusetts, by Tabors Caramanis & Associates with Charles River Associates, April 1996. R. Fagan was a key member of the team that produced the report.

Estimating DSM Impacts for Large Commercial and Industrial Electricity Users. Lead investigator and author, with M. Gokhale, D.S. Levy, P.J. Spinney, G.C. Watkins. Presented at The Seventh International Energy Program Evaluation Conference, Chicago, Illinois, August 1995, and published in the Conference Proceedings.

Sampling Issues in Estimating DSM Savings: An Issue Paper for Commonwealth Electric. Prepared with G.C. Watkins, Charles River Associates. Report for COM/Electric System, filed with the MA Dept. of Public Utilities (MDPU), April 28, 1995, Docket # DPU 95-2/3-CC-l.

Demand-side Management Information Systems (DSMIS) Overview. Electric Power Research Institute Technical Report TR-104707. Robert M. Fagan and Peter S. Spinney, principal investigators, prepared by Charles River Associates for EPRI, January 1995.

Impact Evaluation of Commonwealth Electric's Customized Rebate Program. With P.J. Spinney and G.C. Watkins. Charles River Associates, Initial and Updated Reports, April 1994, April 1995, and April 1996.1995 updated report filed with the MDPU, April28, 1995, Docket # DPU 95-2/3-CC-I. The initial report filed with the MDPU, April 1, 1994.

Northeast Utilities Energy Conscious Construction Program (Comprehensive Area): Level I and Level II Impact Evaluation Reports. With Peter S. Spinney (CRA) and Abbe Bjorklund (Energy Investments). Charles River Associates Reports prepared for Northeast Utilities, June and July 1994.

The Role of Trade Allies in C&I DSM Programs: A New Focus for Program Evaluation, Paper authored by Peter J. Spinney (Charles River Associates) and John Peloza (Wisconsin Electric Power Corp.). Presented by Bob Fagan at the Sixth International Energy Evaluation Conference, Chicago, Illinois, August 1993.

Resume dated September 2010.

ATTACHMENT 2

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

In the Matter of the Petition of Public Service Electric and Gas Company For a Determination Pursuant to the Provisions of N.J.S.A. 40:55D-19

Docket #: EM09010035

(SUSQUEHANNA-ROSELAND)

REBUTTAL TESTIMONY

Steven R. Herling

P-19

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE PETITION OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY FOR A DETERMINATION PURSUANT TO THE PROVISIONS OF N.J.S.A. 40:55D-19 (SUSQUEHANNA-ROSELAND)	:	BPU DOCKET: EM09010035

TO THE HONORABLE COMMISSIONERS OF THE NEW JERSEY BOARD OF PUBLIC UTILITIES:

REBUTTAL TESTIMONY OF STEVEN R. HERLING ON BEHALF OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY IN SUPPORT OF SUSQUEHANNA-ROSELAND TRANSMISSION LINE PROJECT

I. BACKGROUND

Q. Have you previously presented testimony in this proceeding?

A. Yes. I submitted direct testimony in this proceeding, Exhibit P-11.

Q. Have you had the opportunity to review the testimony of Dr. Benjamin K. Sovacool, submitted on behalf of the Municipal Interveners in this proceeding?

A. Yes, I have reviewed Dr. Sovacool's testimony.

II. REBUTTAL OF SOVACOOL TESTIMONY

Q. What is the purpose of your rebuttal testimony?

A. My testimony responds to the testimony presented by Municipal Intervenors witness Sovacool. In particular, I will discuss Dr. Sovacool's comments related to the manner in which load forecasts and demand-side management are factored into RTEP analyses and his comments about the application of reliability criteria and the significance of the reliability criteria violations driving the need for the Susquehanna–Roseland line.

Q. Does Dr. Sovacool make any errors in his testimony regarding PJM's load forecasts?

A. Yes, he does. Dr. Sovacool states that the "original rationale for the Susquehanna–Roseland line was based on an anticipated 4 percent increase in peak demand in 2008." Dr. Sovacool's source is unclear, but the 2007 PJM Load Forecast Report projected a 1.7% peak load growth for the PJM RTO between 2007 and 2008 and a 1.6% peak load growth for the PSEG zone. He goes on to state that "PJM revealed that actual unrestricted peak demand for the summer of 2008 was 10,591 megawatts (MW) and 7.8% lower than summer 2007 demand rather than a 4% increase." In this case, Dr. Sovacool is comparing the difference in unrestricted load experienced over two summer periods to forecasted load for those periods. The relevant forecasted loads are 50/50 loads based on normal summer weather. Unrestricted load is highly temperature dependent. The summer of 2008 was extremely mild, resulting in an unrestricted peak load lower than the load that would have been expected under normal weather conditions. In fact, the normalized peak load for the 2008 summer period was 136,315 MW. While this represents only a 0.2% growth from the 2007 normalized peak load, it is, at least, a basis for an apples to apples comparison. Dr. Sovacool compares the reduction in unrestricted load, a function of weather, to an erroneous predicted growth rate for normalized load. Lastly, Dr. Sovacool erroneously states that the 2008 RTEP relied on the 2007 Load Forecast Report, It did not; the 2008 RTEP relied on the 2008 Load Forecast Report. Dr. Sovacool also states that the PJM load forecast reports are outdated, siting as an example that the 2007 report uses 2006 data. The 2007 Load Forecast Report was issued in January 2007. It is unclear what more recent data could possibly have been used to produce this report than that up through and including the previous summer period.

Q. Do you have any concerns with Dr. Sovacool's discussion of the integration of demand response resources into the RTEP?

A. Yes. Dr. Sovacool states that PJM, in its 2008 RTEP re-tool, "began to recognize Demand Side Management as an explicit adjustment to the unrestricted load forecast." PJM has recognized demand side management in every RTEP since the initiation of the process in 1999 and in its resource adequacy planning process for decades. It is unclear how Dr. Sovacool came to understand that this first happened during the performance of the 2008 re-tool analysis. Demand Response resources are utilized in the evaluation of load deliverability, the test that models the operational conditions under which DR programs can be called upon to interrupt. This was true in the 2007 RTEP when the need for the Susquehanna-Roseland line was first identified and in all subsequent re-tool analyses.

Q. Do you have any other concerns with Dr. Sovacool's discussion of the PJM load forecasts?

A. Yes. Dr. Sovacool makes a number of comments suggesting that a more "accurate" load forecast would delay or eliminate the need for the Susquehanna-Roseland line. It is important to remember that the RTEP integrates a wide range of factors in addition to the load forecast. The RTEP is an on-going process with analyses performed each year, updating all data and assumptions together to provide the most up-to-date assessment of the reliability of the grid and the state of compliance with NERC Reliability Standards. The Susquehanna-Roseland project has been evaluated through three years of RTEP analyses, integrating changing conditions since the original approval of the project in the 2007 RTEP. Even with a wide range of changing system conditions since 2007, the project is still required to be in service by June 1, 2012. Dr. Sovacool points to these very analyses as evidence that changing conditions have resulted in the delayed need for the PATH Project and the elimination from the RTEP of the Indian River – Salem portion of the MAPP project, yet fails to acknowledge that the same analysis has not shown any delay in the need for the Susquehanna-Roseland line.

Q. What does Dr. Sovacool have to say about the reliability criteria violations driving the need for the Susquehanna–Roseland line?

A. Dr Sovacool presents an argument about PJM's planning process and the identification of reliability criteria violations that is difficult to follow. He criticizes my judgment, prior to the completion of the 2009 re-tool analysis, that the Susquehanna-Roseland line will still be required due to the number and severity of the transmission facility reliability criteria violations at issue. He describes my assertion as "specious" since the number and severity of reliability criteria violations is based "entirely on the accuracy of PJM's past load forecasts." First, my assertion, prior to performing the 2009 re-tool analysis, was that the Susquehanna-Roseland line would still be needed. I did not specify when it would be needed, only that I expected that it would still be needed. PJM has always acknowledged that re-tool analyses may result in changes to the required in-service dates of previously approved transmission projects. Second, the number and severity of reliability criteria violations is not based entirely on PJM's load forecasts. It is based in part on load forecasts as it is on generation additions and retirements and a number of other factors. Third, the determination made in the 2009 re-tool was not made based on PJM's past load forecasts, but the most up-to-date load forecast available which included econometric data as recent as December 2008. Dr. Sovacool goes on to say that "if the number and severity of projected violations is not a function of projected load, the only logical alternative is that they are constants" (emphasis added). PJM has not suggested that the number and severity of projected violations is not a function of projected load. Rather, they are not only a function of projected load. The re-tool analysis completed in March 2009, described by Mr. McGlynn, included a significant reduction in forecast peak load and yet the need date for the Susquehanna-Roseland line remained June 1, 2012. It is unclear what Dr. Sovacool is suggesting in the second half of his comment. The number and severity of projected violations is a result of the RTEP analysis. To suggest that it could be a pre-determined constant is absurd. PJM has always been clear about the purpose of its re-tool analyses. Because assumptions can change over time, PJM revisits earlier decisions, through its re-tool analyses, to establish the degree to which the number and severity of projected violations may have changes and to determine whether the need date for a previously approved transmission project may have changed. Reliability criteria violations were identified, beginning in 2012, in the 2007 and 2008 RTEP analyses. PJM updated this body of analysis in March 2009, and the continued need for the Susquehanna-Roseland line in 2012 was clear. As Mr. McGlynn describes in his rebuttal testimony, there are 23 violations in the most recent RTEP analysis that are resolved by the Susquehanna-Roseland line.

Q. Please address Dr. Sovacool's assertion that a more accurate load forecast is likely to reduce or eliminate the reliability criteria violations underlying the need for the Susquehanna-Roseland line.

A. Dr. Sovacool suggests that additional demand response and energy efficiency resources will eliminate the criteria violations driving the need for the Susquehanna-Roseland line. PJM integrates demand resources and energy efficiency into the RTEP when they are reasonably expected to be available, based on their having cleared through the RPM auction. Additional demand response resources will potentially help to resolve reliability criteria violations associated with PJM's load deliverability criteria, which represents the operational conditions under which those programs can be called upon. The additional resources cleared in the 2012/13 RPM Base residual Auction may or may not delay the onset of load deliverability criteria violations, and any delay would, at most, be 1-2 years. Moreover, these resources will have no impact on the NERC Category C criteria violations, i.e., double circuit tower line contingencies, which Mr. McGlynn discusses in his testimony. PJM tests NERC Category C events at summer peak load conditions, but not at the emergency peak load conditions used to test NERC Category A and B events. While demand response resources can be called upon, operationally, in the emergency conditions under which NERC Category A and B events are evaluated, they can not be called upon in the conditions under which Category C events are evaluated. Since demand response resources are not available operationally, they are not relied upon in planning as a solution to NERC Category C violations. As a result, the additional demand response resources available in the 2012/13 RPM auction will not change the need date for the Susquehanna-Roseland line as they will not address the NERC Category C violations.

Q. What about Dr. Sovacool's comments regarding energy efficiency?

A. Dr. Sovacool talks, at length, about his belief that energy efficiency and demand side management programs will be more cost effective, more reliable, and more secure than backbone transmission solutions to reliability criteria violations. Demand response and energy efficiency programs are integrated into the RTEP based on the certainty provided by those programs having cleared through the RPM auctions. This treatment has been thoroughly vetted through the PJM stakeholder process with respect to the development of the RTEP procedures. In fact, all aspects of the RTEP process are reviewed through a number of PJM committees, and specific procedures govern the approvals required to implement changes to the provisions of the PJM Operating Agreement that define the RTEP process. Many of the energy efficiency programs contemplated for future implementation in PJM are far too uncertain to rely on, today, for transmission line planning purposes. To do so would be inconsistent with the stakeholder approved process and would jeopardize reliable service to customers within PJM. These programs will be factored into the RTEP as the means to implement the programs develop to the point where they are willing to commit and bid into the RPM auctions.

Q. Please describe some of the uncertainties you are concerned about.

A. PJM has had to deal with significant uncertainty in the RTEP process with respect to the placement of future generation resources. To date, approximately 85% of proposed generation capacity has dropped out of the interconnection queue. Many of these projects could have contributed to the resolution of future reliability problems on the PJM system, yet despite the stated best intentions of developers the uncertainty around these projects makes it inappropriate to consider them as solutions until they are well advanced in the process, i.e., until they have executed an Interconnection Service Agreement.

The uncertainties surrounding developing demand response and energy efficiency programs raise a number of concerns regarding their implementation into the RTEP. While PJM is supportive of efforts by the states to develop demand response resources and to further energy efficiency, the targets that have been set may not be attainable, the levels that are attainable may be slower in coming than desired, and they may or may not be sustainable over time. As with proposed new generation, PJM must have a reasonable level of certainty as to the availability of these resources if the reliability of the grid is to depend upon them. Once generating resources are constructed, they can be expected to remain connected to the system for decades and their operational behavior is highly predictable. Demand response resources may or may not continue to be available to PJM from year to year. Many forms of demand response are a function of voluntary customer behaviors and are not under the control or direction of system operators. Energy efficiency programs are largely new, in concept, and there is no track record for the sustainability of the demand reductions that may result. These factors suggest the need for a conservative approach to the integration of these resources into the RTEP.

Q. Do you have further concerns about integrating demand response and energy efficiency programs into the RTEP?

A. Dr. Sovacool talks about the benefits of demand response and energy efficiency, but fails to consider other effects of these programs. For example, one obvious consequence of reduced energy consumption will be reduced levels of energy generated and reduced

Locational Marginal Prices paid to generators for that energy. It is well known that energy prices are higher, on average, in New Jersey than in states further west in PJM. As wholesale energy prices are reduced, marginal generators in the east will run less often and will be less profitable. If significant conservation and demand side management were to occur, it is likely that some of these marginal generating resources will be retired from service. In this regard, I note the following:

- Since 2003, fifty-six generators have been retired, removing 5862 MW from service. Almost 1250 MW of these generators were in the eastern Mid-Atlantic region of PJM.
- There are approximately 7500 MW of generation over 40 years old in the eastern Mid-Atlantic area of PJM.
- In the most recent base residual RPM auctions, 5211 MW of generation capacity failed to clear for the 2011/12 period and 6346 MW failed to clear for the 2012/13 period. Absent a revenue stream for installed capacity, if energy revenues are reduced these generators would have to be considered at risk for retirement. Of these uncleared MW, 50% and 28%, respectively, are in the eastern Mid-Atlantic area for the 2011/12 and 2012/13 periods.
- There are 1130 MW of older coal units in the eastern Mid-Atlantic area of PJM of a size less than 200 MW. As carbon restrictions are implemented, these resources will become at greater risk to be retired and removed from service. If energy use is significantly reduced, it will be very difficult to justify the investment required to operationally maintain these resources.

- In the one year period from June 2008 through May 2009, 102 units (3061 MW) in the eastern Mid-Atlantic region of PJM operated for less than 100 hours. 79 of these units (1848 MW) operated for less than 50 hours.

The conclusion which can easily be reached from this information is that the combination of unit age, environmental restrictions, reduced or non-existent revenue streams and limited operation put a considerable amount of generation in the eastern portion of PJM at risk for retirement. In addition, as discussed earlier, approximately 85% of proposed new generation capacity has ultimately withdrawn from the PJM interconnection queue. If revenue streams become less certain for these projects, it would seem likely that fewer projects will move forward to completion. If consumer demand is further lowered, the risk for retirement will only increase with the very real possibility that the need for imports into the east will increase rather than decrease, thereby increasing the need for the Susquehanna-Roseland line.

Q. Is PJM opposed to demand reductions and conservation?

A. Absolutely not. These measures can provide value in a number of ways, but, they are not a substitute for a reliable transmission system. Rather, they should be considered a part of the solution set. PJM has worked to establish market structures that provide revenue streams to incent the development of demand response and energy efficiency solutions. These programs are fully integrated with PJM's RTEP process, ensuring that resources willing to commit to the market are factored into assessments of compliance with NERC Reliability Standards. As an example, energy efficiency was included in the latest Base Residual Auction for the 2012/13 period. PJM strongly supports and continues to work with state commissions and stakeholders on ways to enhance economic demand response in the PJM market. PJM views price-responsive demand, which allows more customers to respond directly to market prices and to voluntarily reduce their consumption when wholesale prices rise, as the ultimate long-term solution to demand participation. PJM has sought the assistance of State regulators to take advantage of price responsive demand capabilities through their own retail rate structure. PJM has indicated that it is willing to embark on a program to encourage individual States to promptly design their own dynamic rate structures and PJM will support these structures with tools and systems that enable customer response to real-time wholesale prices. In the short term, the PJM Board has approved the re-introduction of incentive payments as an interim measure to enhance progress toward the long-term solution. Under this program incentive payments for demand response will be paid in the top 9% of the hours from the previous year based on full LMP. PJM expects this approach will incent demand response during the highest priced hours, when it is most needed, and should accelerate progress toward the long-term price responsive demand solution.

Q. Do you have any other comments?

A. Yes. One of Dr. Sovacool's final comments suggests that the Susquehanna-Roseland line will be used to deliver energy from fossil-fired generation, which he points out is at odds with New Jersey's goals. He goes on to point out the much lower cost associated with wind generation. Based on these comments, it is important to note the state of the PJM interconnection queue. There are approximately 86,000 MW of generating resources under development at one level or another in the PJM queue. Of these, approximately 44,000 MW are wind generators and over 85% of those projects are in western PJM. Without backbone transmission projects like the Susquehanna-Roseland line, these western renewable generation resources will not be deliverable to serve customers in states such as Pennsylvania and New Jersey which have aggressive renewable standards.

Q. Does this conclude your rebuttal testimony?

A. Yes.

ATTACHMENT 3

955 Jefferson Ave.
Valley Forge Corporate Center
Norristown, PA 19403-2497

June 17, 2010

Mr. Lou Cattuna
New Jersey Department of Environmental Protection
Division of Land Use Regulation
P.O. Box 439
Trenton, N.J. 08625

RE: Public Service Electric and Gas Company
Freshwater Wetlands Individual Permit Application
Flood Hazard Area Individual Permit Application
Susquehanna-Roseland 500 kV Transmission Line
NJDEP Application Number 0000-08-0010.1

Dear Mr. Cattuna:

PJM understands that PSE&G has an amended application pending before the Commission seeking permits for the Hopatcong – Roseland ("Hopatcong East") portion of the Susquehanna-Roseland Transmission Line ("the Project"). We also understand that the Commission is considering whether Hopatcong East has independent utility. As the federally-regulated, independent entity responsible for planning transmission to comply with federally-mandated reliability standards, PJM offers this letter to the Commission to support the issuance of the permit for Hopatcong East in order to meet reliability standards.

PJM identified the need for the Project to resolve a number of reliability criteria violations that are expected to occur as early as 2012 and extend out through our 15-year planning horizon. As such, the required in-service date for the entire Project is 2012. Nonetheless, based on the analyses that PJM has performed, there are a number of violations of reliability criteria projected to occur in 2012 that are resolved by the Hopatcong East portion of the line. Importantly, there remain a number of violations in 2013 and beyond that require the construction of the Susquehanna – Hopatcong ("Hopatcong West") portion of the line. PJM is still performing analysis to determine whether any of these violations will occur in 2012, but it is critical to regional reliability that the Hopatcong East portion of the line proceed with an in-service date of June 1, 2012. Even in the undesirable circumstance where the Hopatcong West portion of the line is unable to be constructed, the Hopatcong East portion of the line will provide a critical reliability benefit to northern New Jersey.

Recognizing that the Hopatcong West portion will likely be delayed, PJM will be developing specific operational procedures to manage the risk to the reliability of the region. These procedures will define, among other things, the circumstances under which service to customers in northern New Jersey will have to be curtailed to minimize the potential for broader service disruptions.

955 Jefferson Ave.
Valley Forge Corporate Center
Norristown, PA 19403-2497

Should the Hopatcong East portion of the line not be completed before June 1, 2012, such procedures will also need to be developed to address the reliability issues that are to be resolved by that portion of the line.

Please contact Paul McGlynn at (610) 666-4227 or mcglyp@pjm.com if you have any questions.

Sincerely,

Steven R. Herling
Vice President of Planning
PJM Interconnection, LLC

SRH/nbm: 599122 v2

ATTACHMENT 4

AFFIDAVIT OF
KENNETH J. DALEDDA
ON BEHALF OF
PSEG ENERGY RESOURCES & TRADE LLC
AND PSEG FOSSIL LLC

UNITED STATE OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PSEG Energy Resources & Trade LLC	)	**Docket No. ER05-644-000, *et al.***
PSEG Fossil LLC	)	

AFFIDAVIT OF
KENNETH J. DALEDDA
ON BEHALF OF
PSEG ENERGY RESOURCES & TRADE LLC
AND PSEG FOSSIL LLC

Q. Please state your name and business address.

A. My name is Kenneth J. Daledda and my business address is 80 Park Plaza, Newark, New Jersey.

Q. Please describe your educational background and training.

A. I graduated from City College of New York in 1979 with a Bachelor of Engineering (Mechanical).

During the more than 25 year span of my career at PSEG, first at Public Service Electric & Gas and later for PSEG Power, I have held diverse leadership positions in the power generation field, with responsibility in the areas of operations, engineering, construction, project control and contract management. I initially started as an Engineer in 1983 in the Engineering and Construction Department of Public Service Electric & Gas. I subsequently served as the Engineering Manager for both the Bergen 1 repowering project and the Bergen 2 combined cycle project which included responsibility for project development through turnover to commercial operation. As the Operations Manager for the Mercer Station I was responsible for the safe, reliable and efficient operation of two 325 MW coal fired units. I also had project control experience, managing various plant betterment projects which included projects at Hudson and at gas department metering and regulating stations. From June 2007 until March 2008, I served as Director -

Support Engineering in the Engineering & Operations Support group in PSEG Power. In March 2008, I became the Director of Construction Engineering responsible for engineering related to plant betterment and new construction projects. In August of 2009, I became Director – Engineering, responsible for all engineering for PSEG Fossil LLC.

Q. What is the purpose of this affidavit?

A. By letter order dated June 20, 2006, the Commission accepted tariff sheets filed by PSEG Energy Resources & Trade LLC and PSEG Fossil LLC ("PSEG Power Companies") for a Cost of Service Recovery Rate Tariff ("Tariff"). These tariff sheets implemented a settlement reached by the PSEG Companies with interested parties filed on September 28, 2005 and approved by the Commission in its order issued on November 28, 2005.[1] The Tariff specifies the terms and rates for the provision of reliability services by PSEG ER&T to PJM Interconnection L.L.C. ("PJM") in connection with five generating units located in the PJM region: 21 Sewaren Units 1 - 4 and Hudson Unit 1. Among other matters, the Tariff authorizes PSEG ER&T to receive reimbursement for costs associated with project investments ("Project Investments") needed in order for the units to be operated in a reliable manner.

The Tariff specifies that for Project Investments planned for 2007 and subsequent years, "PSEG ER&T shall file with the Commission for informational purposes, a list of planned Project Investments and costs, with appropriate support, by no later than October 1 of the previous year." The purpose of my testimony is to satisfy this requirement for Hudson Unit 1 for the year 2011. A list of 2011 Project Investments is enclosed as part of this Informational Filing and as explained below, includes certain deferred 2010 project investments for work that will no longer be performed in 2010. Additionally, I explain the rationale for providing a second list of 2012-2014 Project Investments enclosed as part of this Informational Filing.

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[1] *PSEG Energy Resources & Trade LLC, et al,* 113 FERC ¶ 61,213 (2005).

Q. For what period of time does PJM require reliability services from Hudson Unit 1 pursuant to the Tariff?

A. Hudson 1 is required to provide reliability services until September 1, 2011. Under the original settlement referenced above Hudson Unit 1 was to provide reliability services until September 1, 2008. It was subsequently extended for two years, and by letter dated January 7, 2009, PJM notified the company that "it will be necessary to extend the term for this unit one additional year, from September 1, 2010 to September 1, 2011."

Q. Please describe Hudson Unit 1.

A. Hudson 1 was previously described, in detail, in the February 24, 2005 application. Briefly, however, Hudson 1 was commissioned in December of 1964. It currently operates as a gas fired unit with an installed capacity rating of 355 MWs. Hudson 1 is inefficient by modern standards and currently operates at a very low operating factor.

Q. Please describe Hudson 1's current condition.

A. As stated in previous testimony accompanying the February 24, 2005 and October 7, 2005 filings, prior to the Tariff becoming effective, it had not been economical for the previous several years to undertake more than minimum maintenance activities in connection with Hudson 1. Because of this fact and because it was anticipated that Hudson 1would be retired, major maintenance projects were not performed.

Significant levels of project investment have been required to ensure the ongoing safe and reliable operation of this unit. Substantial improvements have been made in the reliability of Hudson 1; however, there remains a need to continue these investments. The risk of a catastrophic failure has been reduced; however, there still remains a level of risk that Hudson 1 might suffer a forced outage when required for reliability purposes.

Q. Have the Projects completed thus far had any effect on Hudson 1?

A. Yes. The projects completed thus far have made a major improvement in the ability of Hudson 1 to continue operations and greatly reduced the risks of a catastrophic failure on key components. Hudson 1 was not able to satisfactorily complete its 2010 PJM summer verification test, but was able to achieve a rating of 270 MWs.

Q. Will all of the projects identified for Project Investments in 2010 be performed before the end of this year?

A. No. Actual expenditures for 2010 will be less than the level of Project Investments submitted for 2010. It is forecasted that we will incur $5.5 million out of the $8.9 million submittal in 2010. The remaining $3.4 million in work from this amount will be applied instead to outage work in March 2011. This has occurred because the unavailability of needed internal resources to plan and implement the project work. Lists of the Revised 2010 Project Investments and the Original 2010 Project Investments are enclosed as part of this Informational Filing.

Q. Will any of the major maintenance items identified in 2010's Project Investment not be performed for 2010?

A. A total of $3.4 million dollars worth of work is being shifted from the 2010 budget to the 2011 budget.

Q. Please describe the Project Investments planned for 2011 that you believe are needed for the units to be operated in a reliable manner.

A. Given PJM's decision to extend the reliability services from Hudson Unit 1 through September 1, 2011, the station has had to reassess equipment condition and readiness to safely and reliably meet this commitment. Project investments for 2011 include major maintenance to correct known critical areas of equipment deficiency. Continued investment for major maintenance on the boiler, turbine and balance of plant are necessary for continued operations with a moderate level of risk of suffering a forced outage.

The overall estimate for the boiler, turbine and balance of plant work is $9.9 million as detailed in the list of 2011 Project Investments enclosed as part of this Informational Filing, including the $3.4 million shifted from the 2010 budget to the 2011 budget. The most significant of the Project Investments for 2011 involves the repair of turbine seals, boiler ductwork and windbox casing and low pressure feedwater heater controls. Failures in these and similar areas have frequently limited load and may create unsafe conditions for station operating personnel.

In addition, there continues to be challenges with the critical weld inspections, boiler tube inspections, and turbine auxiliary systems that require inspection and repair in the next available outage. For the balance of plant, there is a need to replace aged piping and valves, additional work on the high pressure heaters, general valve repairs, and miscellaneous preventative maintenance tasks.

Q. **How were these Project Investments identified and the cost estimates developed?**

A. A broad scope of work was reviewed with senior management and prioritized based upon the expected impact to operations and unit reliability. Specific project investments and required scope of repair were evaluated with a one year time window and focus on assuring reliability and operability. Project Investment estimates were developed using the knowledge, past experience and best engineering judgment of numerous personnel within PSEG Fossil who have performed similar work scope on numerous occasions and at other PSEG Fossil sites in the northern New Jersey region. Of course, there always remains the risk that in the course of performing the actual work, you will find that the extent of conditions may be worse than estimated, requiring an amended scope of work.

Q. **Do you have other support for the Project Investment and costs?**

A. Yes. RCM, an engineering consultant with significant experience in evaluating generating units performed an independent review of the material condition of Hudson Unit 1. This report was completed on September 2, 2010 and provided recommendations on repairs, major refurbishments, and replacements for the next four years. The general need for the boiler, turbine, and balance of plant work proposed herein for 2011 was identified in that report

Q. Do you anticipate that the performance of this planned Project Investment will affect the availability of Hudson Unit 1 to PJM for reliability purposes in 2011?

A. Yes. The completion of these projects is necessary to insure the plant can continue to operate in a safe and reliable manner, consistent with PJM and NERC guidelines and requirements, satisfy the PJM testing requirements, and contribute to further reductions in the level of risk that Hudson 1 might suffer a forced outage when required for reliability purposes.

Q. Please explain why you're providing a second cost estimate for the 2012-2014 time period.

A. Given that PJM has extended the initial RMR period for Hudson 1 three years past the original RMR period, the PSEG Power Companies believed that it is within the realm of possibility that PJM may request an additional RMR extension and may do so for period longer than one year. Although the PSEG Power Companies have not received any indication that PJM will make such a request to extend the RMR period, the PSEG Power Companies felt it would be prudent to quantify the costs associated with extending the life of the Hudson Unit 1 an additional three years if PJM were to file such an RMR request.

Q. Why did the PSEG Power Companies believe it was prudent to provide the additional cost estimate?

A. There are several reasons. Hudson 1 has been operating on an RMR basis for several years from approximately 2006 to 2011. As a result, Hudson 1 has already substantially exceeded the life span originally anticipated in the original settlement and RMR time period. Consequently, the short term investments necessary to extend the life of the plant have been done and those types of extensions are no longer possible. Simply put, any further extensions require substantial additional work.

Any future RMR extensions would require major repairs and a larger scope of work to repair the plant and longer lead times to procure the materials and supplies necessary for larger projects. If *any* additional extensions beyond 2011 were required by PJM, the major repairs necessary to meet such an RMR extension may only be possible if the PSEG Power Companies begin the engineering and procurement process in the near term.

To accommodate such major projects, larger repairs and the longer lead times, the PSEG Power Companies felt it would be necessary to begin that process sooner rather than later. Consequently, the PSEG Power Companies concluded it would be prudent to provide the Commission and PJM the cost information the PSEG Power Companies determined would be necessary if the Hudson 1 plant were to be extended for *any* additional time period so that, if such a RMR extension were made, then the PSEG Power Companies would have additional time to properly plan and execute the scope of work and order long lead time materials and supplies. Although the PSEG Power Companies have provided a three year schedule for CY 2012-2014, the same scope of work would be necessary under any time period to insure safe and reliable operations for Hudson 1.

Q. Please describe the Project Investments planned for 2012-2014 that you believe are needed for the units to be operated in a reliable manner.

A. Project Investments planned for 2012-2014 are based on the RCM evaluation report previously mentioned, which provided recommendations on repairs, major refurbishments, and replacements for the next four years. The most significant of the Project Investments for 2012-2014 involves a major turbine overhaul including repair work on the major turbine auxiliary systems such as turbine valves, lube and hydraulic oil systems, and turbine vibration monitoring system; a generator inspection and overhaul; major boiler work including ductwork and windbox and penthouse casing replacement, and boiler reheat tube, cyclone tube, and furnace tube replacements.

Projects on the balance of plant include major boiler feed and condensate system pump overhauls and repairs to the feedwater heaters; replacement of the unit's circulating water intake screens for NJDEP compliance; and replacement of degraded plant piping systems and valves. In addition, repairs to the unit's structural steel and stack are recommended, as well as repairs and upgrades to the unit's instrumentation, controls and electrical systems.

Q. How were these Project Investments identified and the cost estimates developed?

A. A broad scope of work was reviewed with senior management and prioritized based upon the expected impact to operations and unit reliability. Specific project investments and required scope of repair were evaluated with a one year time window and focus on assuring reliability and operability. Project Investment estimates were developed using the knowledge, past experience and best engineering judgment of numerous personnel within PSEG Fossil who have performed similar work scope on numerous occasions and at other PSEG Fossil sites in the northern New Jersey region. Of course, there always remains the risk that in the course of performing the actual work, you will find that the extent of conditions may be worse than estimated, requiring an amended scope of work.

Q. Do you have other support for the Project Investment and costs?

A. Yes. RCM, an engineering consultant with significant experience in evaluating generating units performed an independent review of the material condition of Hudson Unit 1. This report was completed on September 2, 2010 and provided recommendations on repairs, major refurbishments, and replacements for the next four years. The general need for the boiler, turbine, and balance of plant work proposed herein for 2012-2014 was identified in that report

Q. Do you anticipate that the performance of this planned Project Investment will affect the availability of Hudson Unit 1 to PJM for reliability purposes in 2012-2014?

A. Yes. The completion of these projects is necessary to insure the plant can continue to operate in a safe and reliable manner, consistent with PJM and NERC guidelines and requirements, satisfy the PJM testing requirements, and contribute to further reductions in the level of risk that Hudson 1 might suffer a forced outage when required for reliability purposes.

Q. Does this conclude your testimony?

A. Yes.

ATTACHMENT A
TO THE
AFFIDAVIT OF
KENNETH J. DALEDDA
ON BEHALF OF
PSEG ENERGY RESOURCES & TRADE LLC
AND PSEG FOSSIL LLC

PSEG Fossil LLC
Hudson Unit #1

2010 Reliability Assessment
Technical Report

Final
September 2, 2010

RCM Technologies
The Source of Smart Solutions

2500 McClellan Avenue
Pennsauken, NJ 08109

TABLE OF CONTENTS

1.0 EXECUTIVE SUMMARY

1.1 Introduction

The purpose of this evaluation was to identify, and prioritize, the repairs and/or major maintenance that may be necessary to continue reliable operation to the end of the current RMR period, ending August 30, 2011 and a possible extension of operation for three(3) additional years ending August 30, 2014. The most probable operating scenario is that Unit #1 would be called to operate most frequently during the summer season, from June through mid-September, especially if there are extended periods of hot weather such as what occurred in 2010. However; the unit may also be called to operate during non-Summer seasons such as during severe winter weather events.

1.2 Summary of Findings

- During the summer of 2010 Unit #1 was called upon more frequently than the four(4) previous years and operated with an availability of 80% (YTD July 2010)
- A small number of major repairs to critical equipment and a large number of repairs, restorations, and replacements is required to BOP equipment and components to continue safe operation and to reduce the risk of a major failure and forced outages during the projected additional Summer seasons.
- Normal inspection, overhaul and preventative maintenance needs to be done to ensure reliability.
- Consideration should be given to reinforcement of the plant staff including operating, maintenance and engineering support personnel.
- Certain expenditures and work should be accomplished early on for continued reliable operation through the service extension years of 2012, -13, and -14.

2.0 SUMMARY OF THE STATE OF THE PLANT

2.1 General Summary

The plant is almost 50 years old, having entered service in 1964.

Operation on coal continued for less than a decade. Since the early 1970's the unit has burned No. 6 oil and/or natural gas. In 1999, eight cyclone burners were replaced on the boiler. The economics of system dispatch have resulted in the unit not operating in a base load condition for many years. Statistics provided by PSEG for the last decade are shown below.

In 2008 & 09 the unit ran solely to demonstrate capability. It has been since 2005 since operating hours exceeded 500 and 2002 & 03 since it was about 1000 hours. Data provided by PSEG Piping Engineering, from informal records, estimated that over its life Unit#1 may have accumulated 155,000 as of 1999 and the limited run time in the 2000's would bring the total to the order of 165,000 hours. The unit is considered old by the calendar but not by the hours of service.

HUDSON 1	July YTD	2009	2008	2007	2006	2005	2004	2003	2002	2001	2000
Capacity MW	355	355	355	355	355	355	355	355	355	355	355
Capacity Factor %	2.79	-	-	0.36	0.41	4.05	2.22	5.29	11.26	7.61	4.91
Service HRS	341	55	134	170	195	685	474	940	1,624	1,210	957
Unavailable HRS	957	3,004	1,508	1,328	3,838	1,759	2,206	2,100	1,018	663	827
Economy Outage HRS	3,790	5,701	7,141	7,262	4,727	6,316	6,104	5,720	6,119	6,886	7,061
Availability											
Availability %	81.19	65.71	82.83	84.84	56.19	79.92	74.88	76.02	88.38	92.43	90.58
Eqv. Availability %	79.16	64.12	75.35	66.25	49.53	68.58	67.08	74.91	88.06	92.43	90.58
EFORD %	21.66	2.42	61.58	49.58	49.74	14.18	37.64	24.54	2.66	0.68	1.31
XEFORD %	21.66	2.45	61.58	49.58	49.74	14.18	37.64	24.54	2.66	0.68	1.31
FOR-M %	5.22	20.40	17.18	26.95	21.75	15.43	24.54	13.19	4.08	7.57	9.42
Generation											
Gross Generation MWH	67,019	12,925	25,780	36,152	45,926	164,850	107,510	207,260	398,100	278,170	194,580
Light & Power MWH	16,672	24,326	28,082	24,871	33,165	38,875	38,200	42,737	47,836	41,570	41,346
Period Net Gen. MWH	50,347	(11,401)	(2,301)	11,281	12,760	125,975	69,310	164,523	350,264	236,600	153,234
Off Line L & P MWH	11,364	23,550	25,964	21,125	29,146	27,705	29,997	28,081	24,300	22,700	27,930
On Line Net Gen. MWH	61,710	12,150	23,663	32,406	41,906	153,680	99,307	192,604	374,564	259,300	181,164
Synch MWH	0	0	0	0	0	0	0	0	0	0	0
Fuel Burn			0	0	0	0	0	0	0	0	0
Solid Fuel MB	0	0	0	0	0	0	0	0	0	0	0
Liquid Fuel MB	0	0	0	0	0	0	277,394	2,038,576	291,893	898,191	622,496
Gas Fuel MB	921,038	225,768	376,228	535,764	575,875	1,922,569	1,106,352	344,165	4,140,214	2,238,092	1,639,567
Ignition Fuel MB	0	62	34	158	100	214	118	525	316	231	164
Total Fuel MB	921,038	225,830	376,262	535,922	575,975	1,922,782	1,383,864	2,383,266	4,432,423	3,136,514	2,262,227
Sync. Cond. Fuel MB	0	0	0	0	0	0	0	0	0	0	0
Solid Off L. Fuel MB	0	0	0	0	0	0	0	0	0	0	0
Liq. Off Line Fuel MB	0	49	49	191	62	68	0	100,526	0	20,585	26,653
Gas Off Line Fuel MB	16,465	58,561	47,866	84,242	60,317	90,561	79,820	47,582	83,184	119,010	89,547
Total Off L. Fuel MB	16,465	58,672	47,949	84,591	60,479	90,842	79,938	148,632	83,500	139,826	116,363
Total On Line Fuel MB	904,574	167,158	328,313	451,330	515,496	1,831,940	1,303,926	2,234,633	4,348,923	2,996,689	2,145,863
Gas Correction MB	0	4,533	5,953	28,029	(6,361)	7,950	123,008	0	5,168	90,006	8,853
Survey Adjustment MB	0	-	-	-	-	-	-	-	-	-	-
Heat Rates & Values			0	0	0	0	0	0	0	0	0
Period B/KWH	18,294	0	0	47,506	45,138	15,263	19,966	14,486	12,655	13,257	14,763
Operating B/KWH	14,858	13,758	13,875	13,927	12,301	11,920	13,130	11,602	11,611	11,557	11,845
Bogie B/KWH	9,819	9,401	9,725	9,580	9,567	9,514	9,652	9,403	9,662	9,452	9,761
Op Factor %	49.28	46.35	42.68	45.38	28.58	25.30	36.04	23.39	20.16	22.27	21.34
Oil-BC MB/BBL	0	-	-	-	-	-	6.20	6.20	6.20	6.25	6.20
Gas MB/MCF	1.0186	1.03	1.03	1.04	1.03	1.04	1.04	1.06	1.04	1.04	1.03
Coal MB/TON	0	-	-	-	-	-	-	-	-	-	-
Ignition MB/BBL/MCF	0	5.64	5.64	5.64	5.90	6.10	5.64	5.64	5.64	5.64	5.64
Other Misc. Op Data			-	-	-	-	-	-	-	-	-
IS Starts #	1	5.00	3.00	10.00	6.00	7.00	12.00	8.00	10.00	15.00	11.00
IS Start Fails #	0	-	-	-	1.00	-	-	-	-	-	-
Sync. Cond. Starts #	0	-	-	-	-	-	-	-	-	-	-
Test Starts #	0	-	-	-	-	-	-	-	-	-	-
Start Success %	100.0	100.0	100.0	100.0	85.7	100.0	100.0	100.0	100.0	100.0	100.0
Avg. Cir. Wtr. Temp.	56.9	57.9	59.5	61.5	62.7	62.7	61.5	60.2	63.1	61.1	59.6
Avg. Load in Serv. MW	148	(206)	(17)	66	65	184	146	175	216	195	160
Max. Net Load (60 min) MW	269	364	302	356	357	0*	382	380	389	395	394
Date - Hour	07/23/10 22	03/13/09 20	08/21/08 14	08/20/07 14	02/07/06 13	-	02/23/04 17	08/22/03 17	06/11/02 17	01/04/01 11	06/02/00 12

** Note: error in data for this year*

Because of the cyclic operation for many years and the intended retirement in 2011, Unit #1 has not received the inspection and normal/preventative maintenance that would be routinely performed on a unit with a longer expected service life. The more frequent calls for a start and extended operating hours during Summer 2010 has placed a severe burden on the operating and maintenance staff. The on-line statistics for 2010 are actually not bad considering the state of the plant and the number of forced outages. The unit had 350 service hours and an availability of about 80% when called upon and a start-up success record of 100%, as of July 2010.

Some generalized observations are made. A few anecdotal illustrations demonstrate the maintenance required.

- The outward physical condition of the Plant, the equipment and the structures is not good.
- There are many instances of known material deterioration due to the corrosive effects of exposure to the weather, water leaks, hot gas leaks and deterioration of weather protection surfaces. There may be more corrosion failures from the outside of components due to these effects than the normal old plant failures due to corrosion, fatigue, and stress from the inside or process side.
- The most visible problem, mentioned by plant personnel interviewed is that the boiler air ductwork leaks so badly that they cannot maintain windbox pressure for air supply to the cyclones.
- Leakage of hot gas from parts of the boiler and water leaks and flooding of low areas has caused collateral damage to nearby equipment making it inoperable.
- The sum of the steam/water leaks draining to the condenser is so large that hotwell temperatures are above 130F and backpressure is high. This causes a drastic rise in heatrate and results in higher than design heat rejection to the river. Environmental licensing compliance is managed by reducing the MW output.
- The sum of the mass losses from leaking boiler drains is high and the make-up Demineralizer cannot keep up with and the high make-up. Portable treatment units are brought in on trailers to supplement the plant equipment.
- Continual problems with water and dirt in the turbine oil system, due to deteriorated turbine steam seals, leads to constant problems with valve actuators. The turbine intercept valves require assisted opening due to valve seat and stem bushing binding.

2.2 Requirements for Extending Service 3 More Years

Inspections, repairs, maintenance and improvements must be made to satisfy the following critical criteria:

1. Ensure continued safe operation:
   - Safe for the plant operating and maintenance staff
   - Avoid catastrophic failures which might cause severe collateral damage to either Unit#1 or #2.
2. Comply with all environmental requirements:
   - Stack emissions
   - River intake & discharge and thermal limits
   - Wastewater discharge
3. Provide start-up and operating reliability that is adequate for the intended service.
   - The projected capacity factor is estimated to be approximately 12% based on historical operations. See further discussion below.

Certain levels of small (limited, short-term) failures may occur if the number of occurrences and duration of outage impacts can be reduced and controlled. However, what cannot be accepted is the failure of certain critical pieces of equipment that have no backup redundancy, cannot be repaired/replaced in a couple of days, or which might cause collateral damage.

Some illustrative examples are useful:

- The loss of the main step-up transformer might mean the end of service life for the plant due to the time and expense of replacement.
- Additional small leaks in the air ducting can always be repaired one-by-one when they happen. A general collapse of a major section cannot be accepted. Major leaks of hot gases from the boiler casing or gas ducts are a safety hazard that can damage the equipment.
- The failure of major hangers and supports for high energy piping, boiler pressure parts or ductwork due to deterioration from weather exposure would result in an extended outage and is a safety hazard.
- Major failure of boiler pressure parts that fail toward the outside of the Unit are difficult to access, and jeopardize the operation or maintenance of Unit 2.

As part of the going forward program RCM is mindful that PSEG needs to find a way to anticipate latent problems that have not yet become known and visible issues. The plant staff has been amazingly resourceful in dealing with what they see and experience so far and have a good idea of the known material conditions. An increased level of inspection and preventative maintenance is required to identify what issues that may exist on Unit #1 in addition to those already reported on. high energy piping inspections and the servicing of critical motors and electrical switchgear are examples. Minimal preventative maintenance has been performed due to a scheduled retirement of Unit No.1 in year 2011.

Detailed technical discussions are provided in the following sections, each dedicated to a portion of the plant.

A matrix of recommended repairs/upgrades/maintenance is provided in Exhibit – 1.

3.0 EVALUATION STUDY METHODOLGY

The RCM team consisted of experienced consultants, each with their respective technical expertise, experience in the following areas:

- Mechanical Equipment & Systems
- Electrical and I&C
- Boiler Systems
- Piping

The evaluation was performed by a series of walk-downs, on-site meetings and interviews with plant operating and O&M staff and selected engineering specialists from PSEG headquarters.

Reference documents from Plant archives were provided by PSEG to analysis status of plant operating condition based on historical data.

4.0 TECHNICAL DISCUSSION

4.1 Boiler Related

General:

Unit #1 boiler, manufactured by Babcock & Wilcox Co. is a cyclone fired, double-reheat, pressurized furnace, once-through supercritical design. The boiler is rated for turbine operation at 2,450,000 lb/hr, 3500 psig and 1000°F main steam, 2,252,000 lb/hr 888 psig, 1025°F first reheat, and 2,030,000 lb/hr, 320 psig, 1050°F second reheat. The rating is nominally rated at 383 MW, and it was placed in service in 1964.[1]

The boiler was originally designed for and operated firing coal and No. 6 fuel oil in eight cyclone furnaces. The boilers were eventually converted to burn natural gas in the late 1960s. Coal operation was halted in 1969 except for a short period in the mid 1970s. The station reports that the boiler now operates solely on natural gas since oil firing was halted in July 2004.

Boiler 1 has four cyclone furnaces in a two by two array located on each of the front and rear secondary furnace walls. Gas igniters are provided in each of the cyclone furnaces. There is an operating burner management systems installed for the main burners. Burner operation is performed manually at the individual cyclone. This boiler has used water injection into each cyclone furnace as the only provision for NOx control. The water injection system is no longer used.

Each boiler is equipped with two motor driven and speed controlled FD fans and two Ljungstrom regenerative air heaters.

Since the 2005 inspection, PSEG has replaced the toggle breeching section and expansion joints located between the economizer outlet and the air heaters.[2] Further, they authorized a number of inspection programs focused on specific boiler components/systems. Among these are:

1. A report dated 8/25/06 by Babcock & Wilcox on the air heater casings, windbox, condition, the gas recirculation ducting, and general boiler casing & lagging condition assessment.
2. A report dated 9/07 by Burns & Roe focused on the air heater casing and the Windbox Condition Assessment and cost estimate.
3. A report dated 4/08 by Sigma Energy Solutions on Unit 1 Availability Needs Assessment. The scope of this report was comprehensive including cost estimates under three different time frames (2010, 2012 & 2014), but excluding boiler pressure parts and structural issues.
4. A report dated 8/25-28/08 by PSEG Maplewood Testing Services on piping associated with; Feedpump Warm-up Line, Reheaters, Feedwater heaters, Main Steam line, Drains, and SH Bypass Line.

[1] *Shaw Report of 3/18/2005, Rev. A* on Unit 1 3-Year Maintenance Plan Review.
[2] *Babcock & Wilcox Report of 8/25/06*

5. A report dated 3/20/09 by APT on the condition assessment of the regenerative air heaters.
6. PSEG has invested nominal resources in the past five years to maintain Unit #1 operability by repairing the Finishing Superheater tube connectors to the Outlet header, and pad welded some areas in the cyclone barrels to repair erosion.

Condition Assessment:

The general condition of this boiler system is considered poor, and it is very likely that extending safe, reliable operation for three years necessitates investment in further inspections, repairs, and preventive actions to further deterioration.

The outcome of the present deteriorated condition of these boiler sections results in:

- Preventing personnel access due to inadequate structural capacity to allow walking on ducts & breeching sections.
- Limiting the boiler to achieve design rating due to excessive air and flue gas leak leakage.
- Compromising reliable operation due to the presence of flue gas, excessive heat, and likely asbestos exposure due to damaged insulation; which currently require that certain areas of the plant have personnel access restricted during operations.
- Reduced reliability due to 2nd reheater tube failures in the pendant loops.
- The beginning of tube failures at the 7th elevation due to external corrosion probably from rain water and contact with saturated insulation.
- Erosion in cyclone barrels due to duct corrosion products being introduced into the boiler via the windboxes.

Evidence of these problems is amply reported in the above mentioned references. Additionally, it is reported that due to deterioration in other Plant systems that the boiler feedwater O_2 level is ~25ppb, versus the industry recommended maximum level of 7 ppb.

Although reliability is a major objective for continued service, the crucial concern is related to boiler safety and curtailing the rate of deterioration of pressure parts from exposure to weather conditions that now affects;

- the suspension level hanger rods,
- the pressure parts at the 7th floor scissor section,
- the drains
- the hot combustion air ductwork,
- the windboxes,
- the penthouse enclosure,
- and the air heaters.

Boiler pressure part reliability is reported as being acceptable with records indicating that failures now frequently occur in the 2nd reheater, which have pinhole leaks and that the unit generally runs even with these small leaks. The root cause of the reheater tube leaks is believed to be O_2 attack since there are no formal layup procedures employed when the unit is out of service. The station is planning a project to install a N_2 generator to serve both Unit#1 and #2 and to restore the N_2 distribution piping.

More troubling is the recent furnace and tunnel area tube failures that leak toward the outside of the boiler setting. These have recently begun to occur. It is reported these failures originate from the OD, and likely resulting from long term exposure to rain water and soaked insulation. This type of failure is problematical as failures can easily become catastrophic, which becomes a personnel hazard and can serve to contaminate much of the Plant with asbestos. This could eventually jeopardize the operability and maintenance of Unit 2.

Cyclones:

All eight cyclone furnaces were replaced during the major outage in 1999. The reliability of the original equipment had deteriorated due to thermal cyclic fatigue in the studded tubing. At that time a number of design features were changed in the new cyclones as coal firing was no longer an option.

Shortly after the new cyclones were installed, PSEG burned heavy fuel oil reportedly with a deficient fuel oil heating system. Since that event occurred, which coincided with an operating upset in which an air heater stalled, a significant amount of 'coking' built up in the cyclones. Subsequently, there was recurring tube failures in tube #4 East & West of Cyclone 12R. In 2003, PSEG developed a Root Cause Analysis in which they concluded that severe overheating resulted from the inadequate cooling during a cyclone shutdown or normal operating mode with coking present.

Since that time and when the Unit was converted to natural gas only, it is reported that erosion wear occurs in the cyclone barrels that is attributed to corrosion products from the air heater and deteriorating ductwork due to rust.

Draft System

The air heaters are reported as being in marginal serviceable condition. The seals were last replaced during the 1999 major outage and based on visual observation are in good condition. Since the expected capacity factor is so low, it is anticipated the remaining life of these seals is adequate. The air heater baskets have not been replaced since the mid-1980s, although there was no record of their replacement on file. Three out of four layers of baskets have been removed, with only the cold end remaining. Only marginal thermal performance remains. The air heater inspection report notes severe deterioration of the casing.

The FD fans are motor driven and speed controlled. There is load restriction during the summer due to fan motor amp redlining likely resulting from the excessive leakage in the hot air ducts and the windbox. Left unabated this will get worse rapidly.

The fan motors have not been inspected in more than fifteen years. Back in 2005, Motor 11, when meggered after being out of service for more than seven days, requires it be covered and heated so as to pass the test.

Back in 2005 it was reported that fan rotors were routinely inspected until 1999. PSEG now reports that they have reinstituted periodic inspection. Since minor cracks were found and repaired prior to 1999 and the mode is cyclic boiler operation, corrosion, cracking and blade failure is likelihood unless continued the inspection program is maintained.

The originally furnished FGR system is no longer functional and some of the components have been removed from the site.

Summary and Recommended Actions:

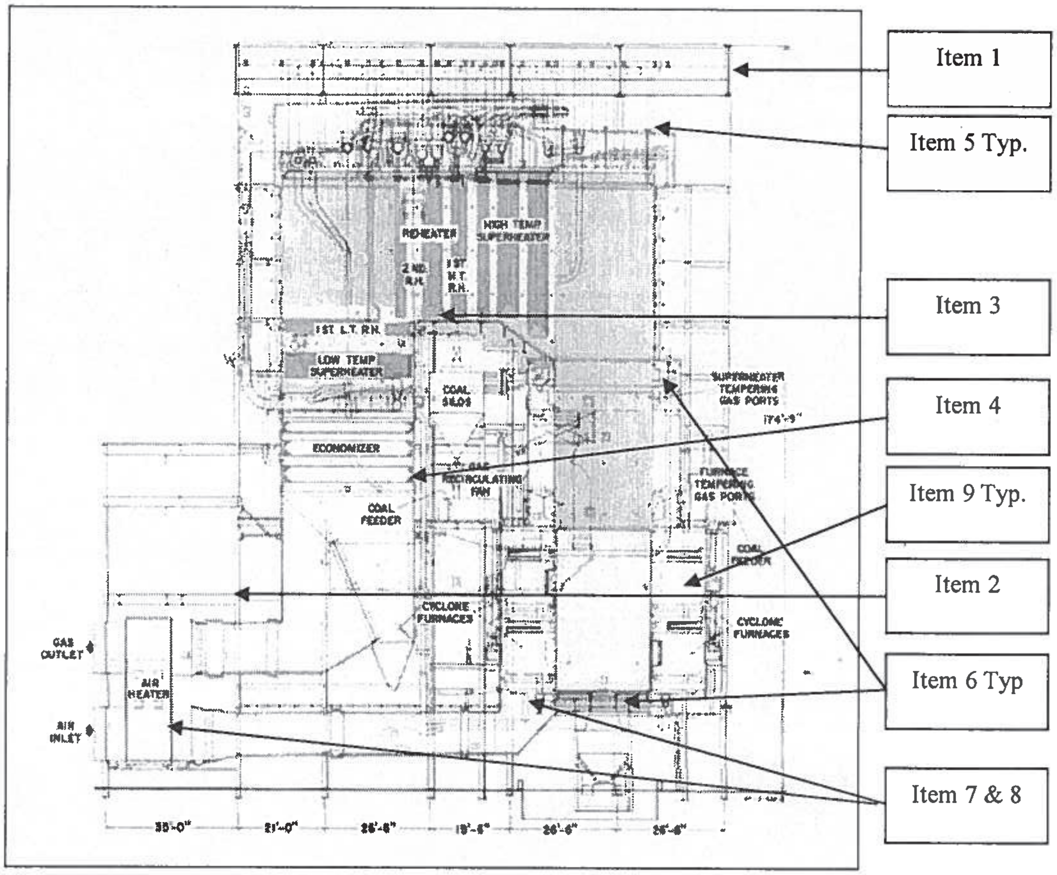
Based on comparative observations between 2005 and now, it is obvious that the physical condition of the boiler has deteriorated substantially due primarily to the exposure of the boiler to the weather. Given that this is a pressurized boiler and that sulfur bearing fuels were historically burned it is likely the combination of sulfur with water is exposing the pressure parts and other components to a very corrosive environment. This must be stopped immediately to prevent an active corrosion process that will eventually produce a very hazardous condition.

Further, the nominal investment being made to it in terms of resources for inspection, repairs and maintenance it is indicative the unit has been 'harvested' during the past few years. The need to extend it's retirement date by three years PSEG requires a reversal of this process. The maximum benefit of additional expenditures for the tasks listed below is if the work is done in early part of 2011.

Because of the three-year window, which is essentially extending the 'harvesting' process already in place, the inspection and maintenance is significantly different than that normally recommended for a 20-year remaining lifespan; only those items considered critical to preserve personnel safety, environmental compliance, and those factors that could cause major forced outages are relevant. RCM considers it likely that the boiler can provide continued safe, reliable service for at least three years if the following actions are implemented with no significant differences in priority ranking:

1. Place a protected cover over and along each side extending down from top steel to the penthouse roofline to prevent further exposure of the boiler enclosure to moisture. This engineered, 'temporary' cover could be fabricated with corrugated lagging material attached to the top steel and major boiler columns and suitable framing.
2. Place a protected cover over the air heater to prevent further exposure of the air heater and ductwork to moisture. This engineered, 'temporary' cover could be fabricated with corrugated lagging material attached to the structural steel with suitable framing.
3. Replace all tube bends for the lower loops of the 2nd reheater now experiencing pitting corrosion.
4. Inspect the lower economizer elements for pitting corrosion as the dissolved oxygen content in the incoming feedwater is ~25 ppb, which is over three times that of the maximum industry recommended guideline. Replace any pitted tube sections and attempt to overdose the O2 scavenger to prevent corrosion of the main boiler circuitry.
5. Inspect and repair any significantly corroded solid hanger rods that extend through the penthouse roof. Historically, these rods are very prone to corrosion when they are exposed to moisture.

6. Inspect visually the exposed pressure parts in the locations depicted below for heavy pitting from the outside. If pitting is found that results in the pressure part wall thickness being less than the minimum ASME Code thickness, remove adjacent insulation to extend the inspection. Special attention must be given to the HAZ of welded joints.
7. Make patches, repairs and replacements of the air heater casing, including structural reinforcement where required.
8. Repair/replace all of the hot air ducting extending from the air heaters to the windboxes and the expansion joints. If repairs are not possible due to the extent of existing damage, it may be possible to use cover plating that are retained with strapping material as an alternative to welding directly to the existing plate work.
9. Repair/replace the windbox on the front and rear of the furnace. This may require extensive asbestos abatement.
10. NDE and repair erosion existing in the cyclone barrel and re-entrant throat sections. Also, periodically clear the barrels of any solid corrosion products that find their way into the cyclones from air heater, ductwork and windbox corrosion.
11. Repair, patch and/or replace sections of leaking flue gas ductwork and ESP casing.
12. Continue performing NDE inspection of the FD fan rotors.
13. Repair or replace all of the boiler drain lines and valves.
14. Miscellaneous repairs and replacements of furnace tubes, HRA tubing and furnace aperture.
15. Restore the N2 layout piping system.
16. Inspect and repair the boiler flash tank and internal components.



Boiler Illustration

Implementation Plan:

The scope of work considered critical for maximizing the chances of attaining a safe, reliable operating boiler for the three years following 2011 is complicated and extensive. Some of these tasks require considerable engineering to satisfactorily implement. Further, the total scope of work required will only be defined once the inspections are complete and evaluated by PSEG Fossil engineering and management.

Given the relatively large amount of potential work, it is recommended the majority of the recommended tasks be combined and bid or assigned to a suitably qualified contractor that is working under adequate oversight. Presumably, a major boiler OEM would be an ideal candidate to accomplish the major boiler scope of work.

4.2 Turbine/Generator

The turbine has not been a constant source of problems or forced outages over the last decade of standby cyclic service. Having said that, the cylinders have not been opened up and a general inspection conducted and overhaul done since 1990, with the exception of LP1 in 1998.

The known problems are as follows:

- Constant problems with water and dirt in the oil system due to poor condition of steam seals.
- Poor quality oil causes malfunctioning of many value actuators.
- Poor oil quality affects the common MHC operation.
- Turbine intercept valves require assistance and frequently "jacking" is resorted to initiate valve opening movement.
- The Bentley Nevada vibration monitoring system is not functioning.
- HP to IP differential expansion instrumentation not functioning
- Steam seal system is degraded and requires steam flow and pressure much higher than design, which contributes to overheating the condenser where it all drains to.

The Operators struggle to get the unit on-line when called and startup requires a lot of operator attention, manual operation and temporary control system modifications based upon operator verification and validation of the equipment status. A significant number of field instrumentation are in poor or failed condition and are not reliable.

The governor is not functional and the unit is run in "load limit" mode. The system needs to be checked-out, repaired and restored to functional condition.

The external turbine accessory systems, steam seals, controls and instrumentation need to be restored to functional condition.

The lube oil system should be completely drained, flushed, and refilled and consideration given to a new, upgraded oil purifier.

The casings need to be opened to replace the shaft seals. This provides the opportunity for inspection and some maintenance of the internals.

Plant operating statistics indicate that actual heatrate in 2010 and recent years has been in the 13-14,000 btu/kw-hr range; about 130-150% of design. Interviews at the plant indicate that this is due to several factors: a) high percentage of FW Htrs typically in bypass due to tube leaks and high condenser backpressure due to excessive drains to the condenser from many sources. The excessive heatrate also impacts plant MW output, because it exacerbates problems with river water heat rejection limitations; which lead to reduction in plant MW load. The reasons behind these numbers need to be further investigated and the root causes understood. The HP heater level controls have been replaced. This needs to be done on the IP and LP heaters and the entire heater drain piping system including valves needs to be restored.

The operating statistics for 2010 show the average load in service to be just under 150MW and the maximum load about 250MW compared to a Summer rating of 355MW.

4.3 BOP Mechanical Equipment, Piping & Systems

Pumps:

The critical steam cycle pumps have been reliable and have not been sources of frequent forced outages. To ensure reliability they should all undergo normal inspection and routine overhauls if not done in the last 5 years or so. No replacements are anticipated.

There are known problems with the Startup Boiler Feedwater Pumps related to deterioration of the pedestal, grouting and/or anchor bolts. The integrity of the pump to pedestal mounting should be restored. There is no information indicating a problem with the deep foundation or the pump assembly itself.

Feedwater Heaters:

The feedwater heaters have a lot of leaks and tube plugs. Frequently several are out of service and bypassed until the unit is off line and access can be gained to insert plugs. The current level of leaks does not appear to be a reliability issue. However the impact of the bypassing shows up as substantial de-rating of MW load and deterioration of heatrate, which exacerbates problems with complying with the river heat rejection limits. The 10 year operating statistics show a lot of hours with heatrate in the 12,000 to 14,000 btu/kwhr range; which is not desirable for a supercritical unit. Additional analysis should be done to determine the cost/benefit of replacing some heaters or tube bundles to get heatrate restored and thereby restore available MW capacity on a hot summer day.

The heater level controls are a constant problem. The recent fixes on the HP heaters needs to be replicated on all heaters. The poor heat drain condition contributes to the heatrate problem because the heater drains are frequently not cascaded and are dumped to the condenser, which raises station heatrate and contributes to the high condenser pressure and temperatures conditions.

Critical Valves:

With the exception of the SH Bypass and the PRV these have not been major sources of unreliability. The SH Bypass valve should be replaced, as well as the PRV operator. Considering the economic impact of a load reduction or outage during the projected additional 3 years of operation beyond 2011, a general program to inspect, restore/repair and/or replace all critical valves is warranted.

High Energy Piping:

There are no known significant lifespan or failure issues with the critical piping. However, outside of the boiler penthouse not much inspection and NDE has been done in over a decade. There may be latent issues that have not yet surfaced due to the limited hours of operation over the last decade. Records indicate that the unit had accumulated about 150,000 hours of operation up through 1999 and less than 10,000 hours since.

In order to continue operation of Hudson Unit 1, inspections and evaluations are recommended to help assure the safety and availability of the unit and reduce the potential for failures of the piping systems. These recommendations are based on limited data about the recent history of the unit. That data includes the operating time and startups, an overview of the recent weld inspection program and limited knowledge of specifics about the unit's recent operations, failures and other relevant data. In fact the first recommendation is to review such data in more depth to verify that it supports the other recommendations.

Much of the basis for these recommendations is derived from the fact that mechanisms of deterioration and failure are quite different for a unit has been operating as a summer peaking unit for the last ten years versus one that has been in continuous operation. Deterioration due to corrosion and weather are more of a concern on a peaking unit that wear and metallurgical deterioration due to creep and other effects. Since most of the critical system piping is stainless or alloy steel, insulated and lagged, corrosion is not much of a concern. However if the weather or other leaks have penetrated the insulation, the exterior of the pipe can be deteriorated. Although this is especially true for carbon steel pipes, it is also true for stainless and alloy pipes. The pipe supports are also subject to the weather and other corrosion and therefore this coupled with their age can lead to failure. Sometimes support failures are very visible but sometimes they are internal and may not be visible. Support failures can result in the release of the support load but they can also result in the inability of the support to move as designed and this can impede the free expansion of the pipe. For these reasons a cursory walk down looking for broken or otherwise dysfunctional supports is not sufficient and a detailed inspection of the supports in conjunction with a pipe position inspection in the cold and hot positions is required.

Considering the findings above, the following is a recommended inspection plan to be carried out in support of three (3) years of service extension beyond 2011 for Unit #1:

1. Review the recent operating history via records or interviews to determine if there are any specific piping or pipe support problems that have occurred. If repairs were performed verify the adequacy of the repair. Review the nature and cause of the problem to determine if there is likelihood of reoccurrence at this location or at other locations with similar conditions. Modify the inspection plan to incorporate this experience data.
2. Review the weld inspection history to determine if there are any specific welds that might be close to failure, have a history of cracking, or are suspect for other reasons. If there are any such welds, perform inspections on them to determine their condition. If there are no such welds, additional programmatic weld inspections are not warranted. If the hanger inspection and hot and cold inspections of the systems reveal any anomalies that would place significant additional stress on any welds, inspections of those welds should also be conducted.
3. Conduct a hanger hardware inspection and cold and hot walk-down inspection of the critical piping systems. These inspections should document the condition of each critical system hanger or support as well as the position of the pipe in both the hot and cold condition. If there have been similar recent inspections, they can be used as a base and the additional inspections can utilize that base and expand upon it. Any defective supports should be repaired. In addition the effect of the defective supports on the pipe stress should be evaluated. Any areas that are suspect should be investigated and monitored during startup as appropriate.

4. Conduct a walk down inspection for non-critical hot lines to identify any deteriorated conditions of the supports or pipe and also and signs that the expansion movement of the pipe may be impeded. Any defective supports should be repaired and their effect on the piping stress evaluated. Any suspected areas should be investigated and monitored during startup as appropriate.
5. Conduct a walk down inspection for non-critical cold lines that are necessary for the operation of the unit. Deteriorated conditions of the supports or pipe should be documented and evaluated. There are known problems with deterioration and leaks of the City Water piping in the basement and with Service Water piping.

Boiler Fuel Gas Supply System:

Numerous reliability issues have been reported with the fuel gas supply piping, valve operation and controls.

Excerpted from the Sigma Energy report:

> *As a result of infrequent operation, the gas stop valve often does not operate without manual intervention. It was reported that during a startup attempt in 2007, the gas valve failed to closed and leaked by. The repair/replacement of this valve was to be addressed in the 2008 fall outage. The gas controls, including the regulators with rubber boot controlled diaphragms, are in the immediate vicinity of the leaking windbox and associated ductwork. The escaping heat exposes the gas burner controls to excessive heat that causes repeated premature component failure and is a safety concern to operators and maintenance staff. Cyclone burners' flame scanner indications are currently inoperative.*

Recommendations are as follows:

1. NDE the gas distribution piping and replace sections where wall thickness indication is less than the minimum required.
2. Inspect and replace burner management controls found to be defective (assume 50%) (Process Instrumentation).
3. The Plant has made repairs and the cyclone burners flame scanners was reported to be currently operative however replacement maybe required, if damaged.

Balance of Plant Piping:

It is apparent that there is much deterioration of general piping because of exposure to weather, system leaks, flooding and spending many hours idle and cold. The failures are typically corrosion from the outside. Specific vulnerable systems include Service Water, City Water and any piping located in frequently flooded areas of the ground floor and the sub-basement areas. Deteriorated piping and inoperable valves in both the City Water and Service Water system should be replaced.

The turbine drain tank and the level controls and pumps should be repaired and/or replaced.

If the general piping is experiencing corrosion failures the supports and instrumentation, IA tubing and valves are also vulnerable and questionable. This may explain the comments about constant water in the Instrument Air System. A general inspection and restoration and replacement should be done of all IA piping and tubing.

Water Chemistry Systems:

The Make-up Demineralizer, Condensate Polisher, and Resin Regeneration systems all have operability and/or reliability issues. Some are internal to the equipment; but others are the result of problems elsewhere that impact water chemistry control.

The amount of cycle steam and water leakage losses raises demand for new make-up water beyond the design capacity of the equipment. This has been compensated for by bringing in Siemens-US Filter trailer mounted water treatment units to produce the additional make-up water required.

There is no on-line water chemistry data available to the plant operator through the control and instrumentation system. Grab samples and manual testing are done frequently to keep up with chemistry trends.

The rubber lining in piping and vessels is clearly deteriorating and the debris ends up causing problems with downstream equipment and valves. The Secondary Condensate Pump suction pressure was lost due to accumulation of debris in the suction strainer.

The resin regeneration system in particular requires a lot of operator attention and manual operation to get it to work. The automatic controls and instruments are not functioning and many small diaphragm pumps and valves are not reliable. The bulk acid and caustic chemical supplier is threatening to stop deliveries due to the too small bulk storage tanks.

Instead of spending a lot of money to make these systems work for only 3 more years; discussions should be held with Siemens-US Filter to determine if it is feasible and economical to turn all functions over to a Service Contractor with his own equipment.

According to Plant staff, water chemistry is not typically a major issue during the start-ups. The technicians must take all start-up readings at the bench, so it does not make much of a difference whether the operators see it in the control room during that time. Additionally, dissolved oxygen is not included in the start-up parameters.

The primary water chemistry issue is more when the unit is online. Once online, the control room has no alarms or reliable indication for the critical parameters that should be continuously monitored when online (i.e. conductivities and pH). Therefore, the Plant must pay overtime to keep a technician on site 24-hours per day while Unit 1 is running so that they can take bench tests every hour. The solution would be to make repairs in order to obtain accurate unit 1 readings on the sample rack, and then to connect alarms/verify all outputs into the recorder in the control room so that they have continuous online indication. The sample rack repairs could simply be transmitter troubleshooting and calibrations, but preliminarily it appears that there are actually issues with physically obtaining sample flow. If the latter is the main cause of the problems, then the costs for repair could increase since new sample lines may need to be installed. Additionally, troubleshooting and inspection of the Unit 1 chemical pumps needs to be done, because they have a history of suddenly failing and causing the boiler pH to drop.

The unit does have higher than recommended levels of dissolved oxygen; however the levels are not terribly high and they can be at least partially controlled with oxygen scavenger (hydrazine). With the unit's limited service, there is not much time for the condensate dissolved oxygen to do considerable damage. More damage occurs when the unit is offline and residual water in the tubes causes corrosion. A nitrogen lay-up would help this situation, however most corrosion damage has been limited to the reheat sections of the boiler, and much of the damage is already done. Refer to recommendations in the boiler section of the report.

With a projected plant capacity factor of about 12% per year for only three more years, the dissolved oxygen should be a manageable issue with current procedures. Repairs should be made to restore continuous monitoring in control room, however.

River Water Intake System:

PSEG Environmental staff indicated that commitments to NJDEP may require that Unit#1 replace the old intake screens with Ristroph fish screens for 316(b) compliance, as was installed on Unit#2 intake.

A summary of the extent of the work is provided as follows.

1. Install new screen assemblies to fit into existing intake structure including new drive system. New screen would need to be designed to interface with existing trough.
2. Make modifications to existing intake structure to accommodate screens (concrete repairs & grout inside intake area, anchor system & grout for screen foundation, other misc repairs of concrete / support structure).
3. Install new service water header piping and screen wash supply piping and control valves for unit 1
4. Install new control panel for the unit 1 screens and screen drives with provide indication/alarm output to DCS
5. Replace upgrade existing screen differential instrumentation system and interface with new control panel.
6. Install new electrical service (breaker, cable, etc) for screen drive motors and control panel.

The following will require inspection and confirmation of operating condition:

1. The screen wash pump was sized for both unit 1 and unit 2, therefore a new screen wash pump will not be required for unit 1.
2. The existing trough system should be utilized so no additional discharge trough would be required for unit 1.
3. There was no major intake structure modifications required for the unit 2 screen retrofit.
4. The trough discharge gate control system installed for the unit 2 system remains – no additional trough discharge gate controls would be required for unit 1.

The permitting and implementation plan for the upgrade is as follows.

1. Hudson's current NJPDES permit requires that intake screens on Unit 1. be upgrade
2. The upgrade schedule is based on the completion date of screens on Unit 2. Unit 2 screens were completed on 6/10/2008.
3. Based on the 6/1/2008 completion date the following schedule is triggered:
4. 6/10/2011: Submit 316(b) Study to NJDEP.
5. 6/10/2011 - TBD: NJDEP will review and approved this Study.
6. 120 days following the approval of the 316(b) Study, Hudson shall begin the implementation of Unit 1 intake screen modification work

The limitations imposed on plant MW output are exacerbated by the non-functioning water flow measurement system, which depends on a "bubbler type" differential water level device. The measured water level differential is used to calculate apparent RW volume flow; which is then used with measured in/out temperatures to calculate heat rejection to the river. Poor level measurements lead to inaccurate flow calculations and erroneously high apparent heat rejection values.

Condenser and Vacuum System:

The condenser was re-tubed with titanium 20 years ago and has not been a source of unreliability. The recent excessively high backpressures are probably the result of other problems that impact the condenser: a) excessive drain flows from feedwater heater drains bypassed to the condenser and high steam seals flow and b) many air in-leaks in piping and valves connected to the condenser due to external corrosion. If these issues are resolve the condenser performance should improve.

The oxygen level is in the 30ppb range and is never near the desired 5ppb level. The high O2 level could be due to a large number of air in-leaks and/or the high make-up flow of un-deaerated, demineralized water into the hotwell.

There are some reports of salt showing up in the condensate and overloading of the condensate polisher resins because of dirty water pulled into the hotwell when the lower pit floods. The Plant has reported that Primary Condensate Pump seals leak and are probably a source of ingested water from the flooded area. A general inspection for leaks and repair/restoration should be done to all of the drain piping and valves connecting to the condenser; as well as an inspection of the tubesheet and condition of the tubes. The hotwell condensate conductivity instrumentation must be fully functioning. If the combination of the in-leaks and the excessive cycle losses and resulting make-up can be brought under control, the number of hours of operation between condensate polisher mixed bed resin regenerations may improve.

4.4 Electrical Equipment & Systems

Introduction:

The major electrical equipment at Hudson Station Unit 1 is original, 1964 vintage. The expected service life of the core power train equipment involved with energy production has not been exceeded given Unit 1 has operated for less than 20 in-service years.

The scope of the assessment was from the generator main (step-up) transformer, the station service (auxiliary and station transformers) the 4160V group and services buses and their associated loads including the 440V and 220V substations, transformers, and associated cabling and loads. The assessment also includes the Direct Current electrical systems.

This assessment utilizes performance data and condition information from existing equipment evaluation reports, operating/maintenance records, and supplemental data gathered from plant personnel interviews and plant walkdowns. Data evaluation was limited to a determination if the reported equipment condition required immediate action to remain in service and be safely operated.

Plant Power Distribution System:

The Generator to Main Transformer operates at 19kV and does not include a generator or transformer circuit breaker, under the control of the plant operator. The backbone of the plant distribution system is medium voltage class electrical service operating at 4KV. The 4KV switchgear services the motor loads greater than 500 horsepower and through step-down transformers the 600V low voltage class substations. The low voltage distribution system operates at 440V and 220V. Power panels and motor control centers provides the local service to plant miscellaneous loads.

The plant electrical distribution design, typical of this vintage plant, did not include redundancy. Therefore; a failure or loss of service event anywhere on the first or second tier of the system will cause an extended forced outage.

The Plant receives auxiliary power for startup through a step-down Station Power Transformer fed from the Marion Switching Station. Once Generator #1 is on-line and tied to the transmission grid, auxiliary power is switched over to the Auxiliary Power Transformer. The Auxiliary Transformer is tapped directly to the 19kV connection inside the Main Transformer.

Power Transformers:

Assessment & Recommendations

Industry experience indicates, as outlined in EPRI "Innovative Methods for Managing Aged Transformer Fleets" that the expected end of life for an oil filled power transformers is 40 years at full load.

PSEG will need to continue to perform routine maintenance, Oil sampling, insulation testing, thermograph, and preventive maintenance functions for the extended service period. The equipment's age limits the margin of safety available to withstand unusual operating events.

Generator Main Transformer

Rating: 230kv/19KV, 475MVA Continuous @ 55°C Rise

Transformer is original 1964 plant equipment, being rewound in the 80's. No record of any major upgrade or rehabilitation performed in later years. Annual testing and a minimal maintenance program has been in-place.

Reported insulation testing and oil samples performed by PSEG Maplewood indicate the transformer is in serviceable condition. Gas analysis history provided shows stable readings back to 1985

The control cabinet requires cleaning and possible replacement of miscellaneous low voltage breakers and contactors. Reported loss of cooling capability identified from reports.

The transformer has experienced oil leaks which have been addressed. Potential for insulating oil leaking to occur will remain and require continuing monitoring.

The transformer has been operated under load conditions for less than 20 years, in the later 10 years at less than rating. The main Transformer is physically disconnected from the utility transmission grid when the Unit is not expected to be in-service. Based upon service life history, it would be expected that the transformer would be in a serviceable condition as reported.

The operation at 355 MW will extend the expected service life of the equipment. There is a reasonable probability that the transformer will perform reliably for the extended service period without requiring any major rehabilitation.

It is recommended that appropriate corrective maintenance on the cooling system be performed.

Auxiliary Power Transformer

Rating: 20KV/4KV, 25 MVA

Transformer is original 1964 plant equipment with no record of any major upgrades or rehabilitation performed. Reported insulation testing and oil samples performed by PSEG Maplewood indicate the transformer is in serviceable condition.

No reports were presented that indicated the transformer needs replacement or extensive rehabilitation. The plants conversion from the original design using coal as the base fuel has reduced the demand for power and in consideration that the unit has operated for less than 20 years, it would be expected that the transformer is in serviceable condition as reported.

Station Power Transformer #1:

Rating: 25KV/4KV, 25 MVA

Transformer is original 1964 plant equipment with no record of any major upgrades or rehabilitation performed. Reported insulation testing and oil samples performed by PSEG Maplewood indicate the transformer is in serviceable condition.

No reports were presented that indicated the transformer needs replacement or extensive rehabilitation. The plants conversion from coal to gas as the base fuel has reduced the demand for auxiliary power. The unit provides power when the plant is off-line or in startup mode. The transformer has been lightly loaded with in frequent plant starts over its service life. It would be expected that the transformer is in serviceable condition as reported.

Medium Voltage Step-Down Transformer

Rating: 4KV/480V – 1250 or 500 KVA

Four (4) gas filled - air cooled outdoor type transformers original equipment installed in 1964. Transformers provide the plant 480V and 220V service through local distribution centers. These units are continuously energized with the connected load varying based on plant operation.

No reports were presented of testing or inspection being performed to access the condition of these transformers. A report was submitted indicating that ambient temperature had exceeded normal levels resulting in the over-heating of the transformer internals as observed from an external temperature meter. The transformers and associated switchgear are located in close proximity to the Boiler.

Testing is needed to determine the operating condition of these transformers. The transformers are in-service and continuously energized and with only one report made available concerning equipment status.

Anticipate only routine maintenance is required for this group of equipment for the extended operation. The cost analysis includes budget to replace two of the four transformer units.

Main Generator & Aux Systems

Assessment & Recommendation

The generator system is original equipment placed into service in 1964. The generator field was rewound in 1989. The manufacturer resolved a rotor tooth top cracking issue, changing the retaining rings to 18-18. Inspections performed prior to 2005 identified some deterioration of internal coatings. A robotic inspection was performed in 2006 recommended that the rotor be removed and the following work be performed:

1. Clean Stator Winding
2. Restore Corona Suppression Paint
3. Re-gap Decoupled Bottom Coil Support Braces
4. Re-Tension Radial Basket Clamps
5. Perform Dynamic Frequency Response Test (Bump)

The report finding did not include a statement that would indicate the potential of an eminent failure event. The above work in addition to a more in-depth inspection and repair should be performed on the generator if the turbine is removed from service for a major over haul. Budget has been allocated to perform an overhaul of the generator.

Report dated 2008 recommended replacement of collector rings and repair of ring heating system. Confirmation was not found that the work was performed. Hi-Pot test performed in 2009 indicate reasonable insulation levels.

Hydrogen cooling and seal oil systems require maintenance service, no record provided indicating the required work was performed. A report provided by PSEG states in part "hydrogen driers for the generator are out of service, allowing for moisture to enter the generator windings". A disposition of the issue was not found in the records provided.

No documents were produced that show the Exciter receiving anything other than routine maintenance or issues with performance. Recommend that testing, inspection and the routine maintenance as required by the manufacturer be performed.

The Voltage Regulator is original equipment and has gone beyond the expected service life. PSEG has been successful at replacement and updating the internal hardware which has extended the equipment service life. The system is performing reliably although the age and obsolescence requires PSEG maintain in-house capability of technical staff and stock of components to maintain the equipment and respond to unexpected failure events.

Recommendations

1. Assuming a less than unit rated peaking operations and appropriate maintenance the Generator should remain operational through the extended operating period with a reasonable level of reliability with routine maintenance only.
2. Replace collector rings .
3. Perform service on the hydrogen system auxiliaries as required (Seal oil and Filters)
4. Perform generator rehabilitation if the Turbine is over-hauled.

Anticipate only routine maintenance is required for the extended operation.

ISO-Phase Bus

Assessment & Recommendation

The Unit #1 Isolated Phase Bus consists of three sealed and forced cooled bus enclosures, one for each phase. Each phase of the bus is supported by ring segments with four insulators on each segment. There is no record of the insulators ever being replaced. After a failure on Unit #2, a cleaning and inspection of Unit#1 was performed. The inspection and subsequent test reports support a finding that the equipment is in serviceable condition. Routine maintenance only required for extended operation.

A dehumidifier was incorporated into the Iso-Phase Bus air ventilation system in response to an earlier failure event. The use of dry air for cooling maintains the insulation level between high voltage internals and case ground. The importance of the added system is recognized when the unit is cycling load with changing operating temperature which can cause the accumulation of moisture within the bus duct. Maintenance of the filters and operation of the dehumidification system is important to the reliable operation of this system.

Recommendation

The bus is a critical high energy component that any failure can become very quickly catastrophic and have the potential of causing major collateral damaged.

Perform routine maintenance to the air cooling system and confirm that the dehumidification system is operational and has been maintained.

Anticipate only routine maintenance is required for the extended operation.

4KV Group Switchgear

Assessment & Recommendation

The 4KV switchgear is a high energy component which serves as the back bone of the plant auxiliary power distribution system. The equipment in-service today is the original 1964 vintage plant equipment. The switchgear consist of protection relays and circuit breakers that are intended to detect and mitigate the damage caused by the failure of a motor, cable or transformer located down stream of the switchgear.

The equipment is theoretically approaching its expected end of service life. The equipment continues to be serviced and maintained in accordance with industry standards. The 4kV circuit breakers are scheduled to receive extensive maintenance and rehabilitation in the 2010 outage. The equipment enclosures appear to be in good condition.

The mechanical based relay system used to perform close-transfer auxiliary service load from the Station Power Transformer to the Aux Power Transformer source is not functioning properly. Recent attempts to perform the transfer have resulted in the loss of the Unit. Recommend that the repair performed on Unit#2 be implemented on Unit #1. The scope includes the replacement of the existing Rochester equipment with a digital based control system.

Recommendation

Replace close-transfer control package for Auxiliary load transfer at 4kV to Aux transformer power source.

Anticipate only routine maintenance is required for this group of equipment for the extended operation.

600V Group Switchgear

Assessment & Recommendation

The 600V class switchgear is assigned to 480V and 220V service level within the plant electrical infrastructure. The four low voltage switchgear equipment are the back bone of the plant 600V auxiliary power distribution system. The switchgear in-service today is the original 1964 vintage plant equipment. The switchgear consists of circuit breakers mounted on a racking system that allows the breakers to be removed without removing the service. The switchgear is intended to detect and mitigate the damage caused by the failure of a motor, cable, secondary distribution panel equipment or transformer located down stream of the switchgear.

The equipment is theoretically approaching its expected end of service life. The equipment continues to be serviced and maintained in accordance with industry standards. The breakers are receiving maintenance and rehabilitation on an as needed basis... The equipment enclosures appear to be in good condition. The switchgear is located in close proximity to the Boiler and has been exposed to high ambient temperature which in one case caused a nuisance trip.

The 480V use a DB25 circuit breaker mounted on a racking system which allows the breaker to be disconnected from the bus and removed from the compartment. The Plant staff reported that the breakers are in good working order. The racking system has not aged as well and is subject to misalignment and jamming. The insertion of the breaker represents a serious hazarder to the Operator if the truck component is not properly aligned and securely inserted with all points of attachment fully engaged. Recommend selected breaker compartments that require routine removal of the breaker be reconditioned.

The 220V breakers are thermal magnetic types which require a minimum of maintenance. The circuit breakers are sensitive to changing ambient temperature and subject to nuisance tripping. Breakers should be cleaned and tested for accuracy of their tripping characteristic. Defective or poor performing circuit breakers should be replaced.

Motor Control Centers

Assessment & Recommendation

The 480V low voltage service is distributed to the Plant miscellaneous load through 34 motor control centers. The MCC's provide protection and control for the motor load and protection for the transformers servicing the 120/208 power panel based loads. The existing equipment is not of the same manufacturer or equal in quality. The useful life of the MCC system will be determined by a combination of aging, environmental and obsolescence factors.

The MCC's manufactured by Federal Pacific appears to have a significant number of issues in this equipment group. Areas where environmental conditions are causing damage, protection measures have been implemented. Parts can still be acquired and modifications based upon readily available substitute components incorporated on an as needed basis to support continued operation.

Recommendation

The complete fleet of MCC's will need selected part replacement and intervening rehabilitation action as part of the routine maintenance.

Protection Relay

Assessment & Recommendation

The main generator and 4KV protective devices are electro-mechanical based devices and considered antiquated by present standards but still functional. Industry experience is if the devices are serviced on a regular basis the units can remain operational through the extended operation period.

Test and maintenance records show this group of equipment has received normal service within the last three years. The available records contain no evaluation or commentary that would suggest the equipment should be replaced or raise performance concerns.

Recommendation

Anticipate only routine maintenance is required for this group of equipment for the extended operation.

4KV Cable System

Assessment & Recommendation

The plant staff has continued to perform a low voltage Megger Resistance Test that covers both motor and cable just prior to return to service after every extended downtime. Reports produced by the plant staff document readings that give no indication of major insulation degradation as would be anticipated from the previous testing results reported for Unit #2. The readings show a trend that the 4KV insulation is in fair condition. Only a small portion of the installed cable is exposed to a continuous wet environment.

Recommendation

The ability to determine an exact date that a cable will fail is not yet a reality. The industry has accepted 60 years as a bench mark for cable useful service life. Application and/or service conditions which vary widely, will determine the actual achievable useful cable life.

1. A near term approach is to continue with the Megger Test and track the results. Perform more advance cable testing if the 4kV motor load is removed from service for rehabilitation.
2. Replace cable on failure or a sudden change in the insulation test results.

Anticipate only routine maintenance is required for this group of asset for the extended operation. Budget allocation provided in anticipation a cable replacement for the most critical motor load.

600V Class Cable System

Assessment & Recommendation

The bulk of the low voltage cable historically has few reported failures which support the available technical paper findings on the subject that sets useful cable life at 60 years. Cable failure can be traced primarily to an environmental condition at a specific location that causes damage by excessive ambient temperature or mechanical stress.

Recommendation

Plant staff needs to be aware that when a high ambient temperature condition is identified requesting an immediate assessment of the impact on adjacent cable installations is required. The investigative effort should target those cables with a high probability of failure and can cause extensive collateral damage.

Anticipate only routine maintenance is required for this group of asset for the extended operation.

4KV Motors

Assessment & Recommendation

There are 11 motors (4 KV) installed in the plant. PSEG maintenance policy and practice for extending the medium voltage motor service life is summarized as follows:

Open Drip Proof Motors

- inspected and refurbished on a 5 year cycle hostile environment

- inspected and refurbished on a 7 year cycle

Totally Enclosed Fan Cooled Motors

- inspected and refurbished on a 7 year cycle

PSEG in the near past was actively maintaining the motors in accordance with the above schedule. The reduction in operating service time and maintenance resource allocation, has translated into Unit #1 4kV motors not receiving the routine service as specified. No indication in written report or staff commentary that the 4kV motors operating status has been compromised through neglect. Heaters, lubrication and other routine maintenance services have continued to be performed on this class of equipment. A Megger reading taken just prior to going back into service has provided a written record of motor insulation condition. The records indicate the equipment is in fair condition electrically and no comments have been offered suggesting mechanical problems.

Recommendation

The mechanical section of this report may suggest a rebuild of the connected load; in that case the motor should be removed and sent to the shop for rehabilitation.

Anticipate only routine maintenance is required for this group of equipment for the extended operation.

Low Voltage Motors:

Assessment & Recommendation

There are approximately one hundred 600V class low voltage motors in various sizes throughout the plant. The equipment is typically an off the shelf purchase so a maintenance program or spare part inventory is not justifiable. Performing standard plant maintenance with replacement on failure is recommended.

Battery Systems:

Assessment & Recommendation

The station battery system consists of a three batteries banks (250VDC; 125VDC and 28VDC battery) along with associated battery chargers and inverters. The 250V batteries provide power to emergency DC pumps and backup 125V power. The 125V batteries provide control power for the 4KV and 480V circuit breakers and for indication on devices feed by the breakers. The 28V battery system is utilized primarily for DCS and control panel indication. Each battery has redundant chargers. The entire DC system can be backed up by the Unit 2 DC system. There are 6 inverters, 4 of which are assigned to UPS. The inverters are backed up by a power conditioner.

The batteries were replaced in 1987 and are at the end of their 20 year life expectancy and need to be replaced. Maintenance records indicate a replacement recommendation has been pending. The reports prepared by an outside contractor indicate the batteries physical appearance gives a fair condition assessment. A load test has not been performed to determine actual battery discharge capability condition. A visual inspection confirmed little sentiment has accumulated on the bottom of the battery container and the plates appear to be hanging straight. A partial discharge test would establish if the batteries have little or no capacity remaining.

The battery chargers, power conditioners, and inverters are at the end of their life expectancy. This group of assets operates continuously and is limited by internal component life specified as MTBF. The Plant Staff has in recent past performed rehabilitation grade maintenance (component replacement) on the existing equipment; effectively extending the service life.

The batteries are an essential asset for the safe operation and protection of the plant. The useful life of the battery is fixed by the chemistry of the internal components. Pro-active maintenance will guarantee the batteries will reach their maximum useful life but cannot extend the life much beyond 20 years.

Recommendation

1. Anticipate the Battery chargers, and inverters should require only routine maintenance to operate through the extended operation period.
2. Batteries will have already exceeded their expected life at the beginning of the extended service period by a number of years. Testing (Partial load discharge test) may help clarify if the batteries need to be replaced immediately. The report recommends replacement in considering the importance of the asset's function to the safety of plant personnel and equipment protection.

4.5 Instrumentation and Control

Introduction:

A Hudson Station-1 instrumentation and control system has not under gone a major upgrade since the early 1990's. The existing plant controls are a mix of old and new technology. Upgrades to turbine/generator and burner management control eliminated local pneumatic and relay logic in favor of remote digital based system with the implementation of the Bailey Infi 90 DCS System in 1989.

Assessment of the control system is most accurately described if separated into two categories of concern. The findings of previous reports addressing Unit 1 operating condition assessment included the following list of major upgrades and replacements to the system:

<u>DCS System</u> (Bailey Infi 90)

- Upgrade DCS Communications Cards and Firmware
- Upgrade DCS Processors and Firmware
- Replace DCS Power Supply Systems
- Replace DCS Analog Input/Output Modules (As required)
- Replace Operator Console Screens (Upgrade to Present Communication Standard)
- *Confirm Operating Logic & Remove all soft jumpers*

<u>Field Devices</u>

- Upgrade Main Control Console Pushbuttons & Status indicators
- Replace IP & LP FW Htr Level Controls
- Replace Critical Valves Operators & Position Sensors
- Replace Damper Positioners
- Replace Flame Scanners (Anticipate high ambient temperature damage see Boiler repair section)
- Replace Turbine Vibration Monitoring System (Turbine, Fan, BF Pump, Air Compressor)
- Replace Major Equipment Vibration Monitoring System (Fan, BF Pump, Air Compressor)
- Replace Turbine Thermocouple and Input Modules
- Replace Boiler & miscellaneous process Thermocouple and Input Modules
- Replace Combustion Chamber Oxygen Sensors
- Replace Pneumatic Control devices (Obsolete/Failed) (Est. 20 Process aux skids)

Miscellaneous Devices

- Install Sequence of Events Recorder (Repair if parts are available from decommissioned equipment)
- Miscellaneous Controls

The upgrades described above were considered essential for a safe and reliable plant operation.

DCS Control Systems:

Assessment & Recommendation

In preparation for Y2K, a proposal was present to upgrade Unit #1 DCS (Distributive Control System) hardware and firmware. The proposal was not funded and very little corrective measures have been taken to upgrade or maintain the DCS system capability. The Plant staff did not identify the DCS as the source of unanticipated failure events.

Plant Operators and Engineering Staff have worked in collaboration to use the DCS to identify troubled field device. The control program has been modified with soft jumpers to allow the plant startup to proceed under the observation and condition assessment of the operator. Even with the afore described activities the plant staff reported that a substantial allocation of manpower is required to perform diagnostics and repair just to maintain a minimum operating status.

The hardware with a manufacturer recommended replacement cycle of 5 years and an extended life of seven years is most likely approaching 10 years in service. The expected service life of the DCS hardware is measured in calendar days. The control system hardware remains energized even when the plant is not in service.

Replacement/Upgrade of selected DCS components (hardware and firmware) is required to ensure some minimum level of reliability and compatibility with the new generation of field modules and recommended hardware replacement for the control console, HMI (Human Machine Interface) and other required items such as upgraded heater level controls, enhanced diagnostics, and boiler-turbine controls.

Installation of replacement and upgrade hardware should significantly improve component controls and system monitoring. A continuing effort to replace end devices to components that are compatible with DCS controls should also improve control function and reliability.

Additional significant benefit that is not as readily apparent is validated control and wiring diagrams.

Instrumentation Associated With Bailey Infi 90:

The majority of problems related to process control reported by the plant operations are associated with field instrumentation performance. This was the dominating issue during our on-site assessment. The problem is especially critical to the operator's safety during startup. The following is a sample of the typical problems with this category of asset:

- DCS tie-in to existing devices not easily accomplished or reliable
- Transmitters that had failed

- Valves without proper feedback signals
- Damper drives not operating

Combustion Control Field Devices: Transmitters, limit switches, and drive units. These devices are showing a raised failure rate, due in a major part to excessive heat conditions on the burner fronts. Typical failures include, drive position feedbacks, combustion valve limit switches, air flow and pressure transmitters. The deteriorated condition of the windbox area causes extremely hot gasses to blow on these devices, causing their failures.

Turbine Control Field Devices: Operations has experienced problems with the operation of, and the feedback from the turbine control valves. Typical failures have included the position limit switches on the Throttle Valves and operation of the Intercept Valves. Poor or unpredictable operation on many of the valves traced to low turbine oil pressures and excessive clearances on the turbine valves. These valves will need repair and rebuilding.

It is recommended that a bottom up assessment of Plant instrumentation condition be performed. The report does not recommend the complete replacement of all instrumentation and pneumatic systems. A focused effort is needed to identify systems that represent the greatest need for intensive labor to safely startup and operate the Unit. Antiquated transmitters should be replaced with the new "smart" transmitters that can be used on Unit#2

Recognizing "startup reliability" is a core concern of this report, any discussion or assessment is that the field instrumentation system in poor operating condition. An accurate and reliable operating instrumentation system is a key element to a safe and productive asset. Failure of the instrumentation to perform can place the asset in jeopardy or effectively reduce component life through in-action or poorly directed action taken without knowing all pertinent process condition facts. The operator stated that the current system when it does provide information is not a trusted source.

Instrumentation Associated With Balance of Plant

The majority of problems related to process control, reported by the plant operations, are associated with field instrumentation performance. As discussed in a previous section and worth re-emphasizing since the problem extends beyond the boiler and turbine equipment. The following is a sample of the typical problems with this category of asset:

- Pneumatic system (solenoids, transmitters) that do not work
- Transmitters that have failed
- Valves without proper feedback signals
- Position and valve drives not operating

The condensate demineralizer (DM plant) regeneration system was originally controlled by a drum type controller that has failed. The resin transfer and regeneration process is presently controlled manually by manipulating toggle switches. This results in inaccuracies in the regeneration process with the potential for accelerated degradation of the resin beds and failure to maintain boiler water quality.

Instrument Air & Pneumatic Systems:

The air compressors are a common component for Unit 1 & 2. The electric service and controls are sourced from the Unit #1 infrastructure. Instrument air conditioning is unit specific. A substantial effort has been put forth to solve issues with the reliability and quality of the instrument air supply for Unit #2. Unit #1 has been neglected and is need of some modification and intense maintenance to provide a reliable source of instrument air. The core issue is the air system is providing air with high moisture content which affect on performance and very troublesome from a winter operation perspective with freezing.

The Unit #1 process infrastructure uses approximately 20 pneumatic systems for control over the various support equipment skids. The components of the pneumatic system are original and are failing. The components are obsolete, making in-kind replacement impossible. An assessment of the pneumatic controls by system of major equipment has not been performed. The practice has been to bypass the automatic control function by operating local hand valves. The practice has resulted with operating systems on-line with minimum remote control supervision and insufficient staff to be assigned for continuous monitoring of system performance from local devices.

Component Useful Life Longevity:

Industry experience shows however; that microprocessor based control systems have finite physical and technical lives. As a result of components having a finite live, spare parts become harder to find, software improves and the next generation of data-highways or communication bus technology comes along, sooner or later. Typically any 1st generation microprocessor control system installed in a power station in the late 1980's has been replaced completely, or largely upgraded because its hardware and software is either worn out, no longer supported and/or obsolete.

The maintenance program and environmental control has maximized the asset longevity but not eliminate the fundamental fact that the system components by design have a limited life cycle. The upgrades recommended by this report are to components which upon failure cause a loss of program function.

Recommendations

1.A modest investment in component replacements and upgrades is required to extend the existing Bailey Infi 90 DCS system. The recommended program is not a complete replacement of the existing plant control system. The majority of older hardware will remain. The processor upgrades, selected hardware replacement and firmware patches will correct the deficiencies of the current system for the short term. The approach will reduce the risk of imminent failure but not eliminate.

   The firmware and the memory of the control and communication modules will need to be upgraded to improve reliability. This upgrade will need to be performed before or at the same time as replacement of the Operator Interface Console to ensure that the communication with the new HMI is stable. The DCS cabinets should have a full "Hardware Cleaning and Shakedown" performed. This includes cleaning of all cabinets and modules and checking all connections for looseness and open circuits.

   The work of cleaning internal components and hardware and firmware upgrades would be performed by Plant Staff Personnel.

In addition, the DCS includes old/obsolete hardware (modules) that should be systematically replaced. A small number of spare modules are being stored on site, but there may not be sufficient quantity to maintain the system thru the expected extended run time period. These modules would be replaced in stages over the next year or two using station labor and engineering. The effort as proposed would be a repair by replacement effort which would be performed over a period of time requiring minimal system down time.

2. Operator's CRT control stations. The Management Command System, which is the HMI for the operators, is obsolete, in poor condition, and parts availability is extremely limited. These consoles need to be replaced. A low end replacement console has been purchased as an emergency backup in the event of a failure during operation. The purchase of 2 additional units would be sufficient to replace the MCS consoles on the unit.

3. A recommendation that a bottom up assessment of the Field Instrumentation condition be performed. The findings would focus on identifying the minimum equipment configuration to safely operate the plant. It is recognized that on multiple train based systems replacement may be implemented to operate with no redundancy.

   Replacement of the six (6) oxygen sensors is recommended. The sensors provided the data necessary to set fuel to air combustion conditions in the boiler. The sensors are necessary for the safe operation of the boiler.

4. The condensate demineralizer (DM plant) regeneration systems original plant equipment failed drum type controller needs to be replaced with a PLC based control system in the near term.

5. The assessment of the integrity of the boiler containment and condition of the external insulation is critical to the Plant operation and reliability. Substantial damage is being inflicted upon the instrumentation and controls located in close proximity to the boiler from breaches in the containment vessel and external protective insulation. Replacement of these critical instrumentation and control devices and the associated cabling is requiring a substantial expenditure of resources just to maintain the most primitive level of control with each hot run of the unit.

4.6 Structures

A general inspection of the condition of the structural steel has not been done since the work done by S&W/Shaw in 2005. At that time S&W did not observe a lot of deterioration to main steel, but noted many issues with platforms and stairs. A more recent inspection (focused on safety) of platforms and stairs was done by Beckmeyer Engineering in September 2009. It is not clear whether all of their observations have been dealt with and repairs made. The deficiencies noted in the report should be repaired. All of the structural steel for the turbine building, boiler and ductwork supports should be inspected and repairs made where indicated.

With the frequent and constant level of flooding and leaks experienced in the lower levels of the turbine and boiler areas, it is expected that there is deterioration of the reinforced concrete floor slabs; which will require repairs and replacements. No detailed assessment has been done. Inspection should be carried out and local repairs made where indicated.

No information was provided to indicate when the last inspection of the stack was done.

The boiler elevator has not been inspected in many years. The unit should be inspected and repaired and restored as required.

The RW intake and discharge piping was last inspected in 2008.

4.7 Environmental

Hudson Unit No. 1 has been typically operated between 2 and 3 lb/MW-hr (net). The boiler may be able to operate at reduced NOx based on how the unit is tuned. Although the NOx RACT emission limit is lowered to 4.3 lb/MW-hr (net) in 2012, the unit should be able to comply based on historical data. If the unit exceeds the 4.3 lb/MW-hr (net), it can utilize NOx averaging for compliance. However, in 2015, the unit will not be able to operate unless it meets a lower NOx emission limit of 1.0 lb/MW-hr (net).

PSEG Environmental staff advised that commitments to NJDEP require Unit#1, if it is to operate past 2011, to upgrade the river water intake screens as was done on Unit#2.

Apparently the unit MW load has recently been constrained by limits on heat rejection to the river. The situation is exacerbated during hot summer days when maximum unit load must be curtailed because of a) excessively high condenser backpressures that increase heat rejection and b) probably erroneous RW flowrate calculated from unreliable water level differentials across the intake screens.

5.0 IMPLEMENTATION, SCHEDULE & COST ESTIMATE

5.1 Implementation Plan

The scope of work considered critical for maximizing the chances of attaining a safe, reliable operating boiler for the three years following 2011 is complicated and extensive. Some of these tasks require considerable engineering to satisfactorily implement. Further, the total scope of work required will only be defined once the inspections are complete and evaluated by PSEG Fossil engineering and management.

Given the relatively large amount of potential work, it is recommended the majority of the recommended tasks be combined and bid or assigned to a suitably qualified contractor that is working under adequate oversight. Presumably, a major boiler OEM would be an ideal candidate to accomplish the boiler scope of work.

Similarly the substantial scope of mechanical and electrical work required to meet stated performance reliability goals will require the additional mobilization of an experienced work force, under adequate oversight.

5.2 Schedule

Whatever level of repairs, upgrades and replacements ultimately decided upon, the investment and the work should be implemented so that the improvements are available for the projected 2012, -13, & -14 years and especially the summer operating seasons. This means the major work needs to be planned for the major outages in spring and fall 2011 and spring 2012.

PSEG should give serious consideration to not assigning the work to the normal plant based multi-small project implementation program. In order to give the effort focus and attention to schedule completion and alternative approach with central dedicated Project Management team and possibly a short list of major sub-contractors should be considered.

The recommended work packages include some large ones concentrated on big items such as the boiler work and a turbine overhaul and a large number of small work packages to restore BOP equipment, systems and components. The interviews of PSEG staff at the plant site made it readily apparent that the staff (operating, maintenance and engineering support) is busy with normal Hudson Unit#2 assignments. When a need for a Unit#1 arises from time to time, people are pulled from their normal jobs and told to take care of the special Unit#1 assignment on an emergency basis. This is understandable in a situation where Unit#1 has not been expected to run very often for many years and was facing imminent retirement. The extension of service life by 3 additional years and the need to give priority to the outages to repair and restore the unit for these additional years will require more staff than are available currently. It is recommended that the repairs and restoration work on Unit#1 be give focus and priority and some dedicated people in a manner analogous to the Unti#2 BET Project. It may be advisable to package much of the work in a few big contract packages assigned to larger contractors; such as B&W for all of the boiler work, Siemens for the turbine generator work, and a general contractor for the BOP work. This approach may provide a better chance of meeting budget and schedule targets than spreading the work and responsibility out to a large number of small contract packages. Some level of Project Management attention and priority needs to be focused on this work to reap the benefits of the expenditures. The work is more than your average annual outage work scope.

5.3 Cost Estimate

Estimated costs are provided in the Report Appendices as EXHIBIT-1 "Matrix 2010 Reliability Assessment".

6.0 APPENDICIES

6.1 Exhibit-1: Hudson 1 Matrix 2010 Reliability Assessment

6.2 List of references documents provided.

1) Three Year Maintenance Plant Review, and cost matrix, S&W/Shaw, March 2005
2) Air Heater Outside Casing, Duct and Wind-Box Condition Assessment, with cost estimate; Burns & Roe, September 2007
3) Hudson Generating Station Unit 1 Availability Needs Assessment; Sigma Energy Solutions, April 2008
4) FURNACE VESTIBULE MIX AREA INSPECTION REPORT, B&W, February 2009
5) Hudson 1 Operating Statistics 2000 thru July 2010
6) Boiler Service Engineering Report, B&W, August 2006
7) HUD 1 FO Event Data Record 2001 – 2010
8) HUD I Critical Weld Data Report (through 1999)
9) HUD 1 Pipe Wall Thickness UT data and summary report, 2008
10) HUD I FW Htr tube plugging table through 2008
11) HUD 1 Records of Boiler Tube Leaks 2009/10
12) Safety Inspection Report (platforms, grating, stairs); Beckmeyer Engineering, September 2009
13) Electrical main one-line-diagram (s)
14) Various mechanical systems piping diagrams
15) Air heater inspection report, 2009
16) Electrical transformers test reports
17) Planned outage cost reports 2008, 2009, 2010
18) Summary of Startup BFP Issues and Recommendations 2010
19) Summary of Remaining Areas with Asbestos 2010
20) 4KV Cable/Motor Startup Megger Test Reports
21) Thermographic Inspection Hudson Unit No.1 Power Train Report
22) Gas Analysis History Hudson Unit No.1 Transformer Report
23) Field Investigation 220VAC Load Center Trip Event 07-20-08
24) Maplewood Hi-Pot Test Results 01-15-09 (HUD-1 Generator, Iso-Phase Bus, 4KV Cable)
25) Planned Outage Summaries (2010 RMR, 2008 RMR)

ATTACHMENT 5

Transmission Expansion Advisory Committee

November 10, 2010

Issues Tracking

Open Issues: None

New Issues:

Baseline Reliability Update

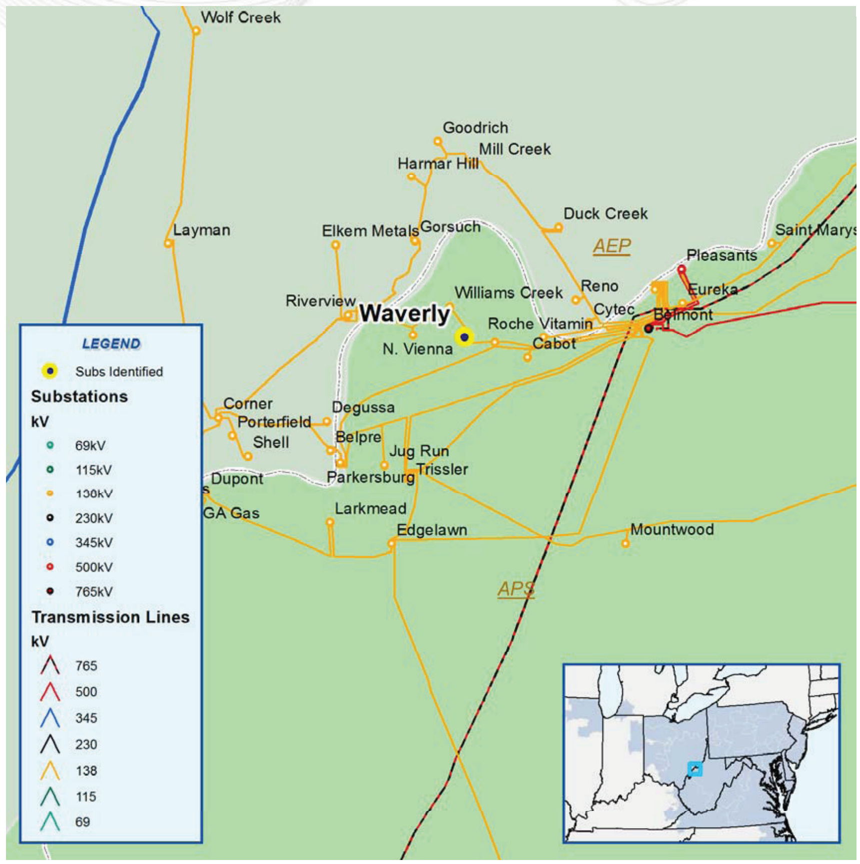
APS Transmission Zone

- N-1-1 Violation:
- Voltage magnitude and voltage drop violation in the Waverly 138 kV vicinity for the loss of Grove – Waverly 138 kV line + Willow – CYTEC-Reno 138 kV line as a result of Gorsuch 189 MW generator retirement.
- Proposed Solution:

  Install 59.4 MVAR capacitor at Waverly
- Estimated Project Cost:

  $0.816 M
- Expected IS Date:

  12/01/2011



2012 Retool Update

- Update to September 2010 TEAC
- Reliability analysis performed without Susquehanna – Roseland
- 2012 Common Mode Outage procedure violations identified

Facility Overloaded	Contingency Type	% Loading
West Wharton - Greystone "J" 230 kV	Double circuit towerline	111.6%*
Newton - Lake Iliff 230 kV		106.5%*
Lake Iliff -Montville 230 kV		105.7%*
Kittatinny - Newton 230 kV		105.3%*
Portland - Greystone "Q" 230 kV		100.4%
Greystone - Whippany 230 kV		99.4%
Kittatinny - Pohatcong 230 kV		98.0%
Glen Gardner - Chester 230 kV		95.4%

* Conductor limited

- Incremental upgrades not practical given a number of the violations exceed conductor limits
- PJM evaluated the effectiveness of retaining Hudson 1 on RMR into 2012
- PJM performed preliminary market efficiency analysis of 2012 and 2013 to determine the impact of operating to double-circuit tower line contingencies due to the delay in Susquehanna – Roseland 500 kV

- Market efficiency analysis assumed Hudson 1 remained in-service in 2012 and 2013
- Study results
  - net increase in gross congestion in each year primarily in New Jersey
    - ~ $160 Million in 2012 and ~ $ 280 Million in 2013
  - Increase use of demand response to control constraints
  - Constraints could be controlled with the addition of Hudson 1 and the implementation of demand response

- PJM will develop plans to operate to the double-circuit tower line outages in real-time operation
- PJM will request the Hudson 1 unit be retained on RMR through at least 2012
- PJM will complete additional reliability and market efficiency analyses based on queued generation

Remaining 2010 RTEP Analysis

- 2014 Retool Analysis is in-progress
- Potential for voltage violations
- Core SVC locations (from MAAC alternative analysis)
  - Jacks Mountain, Doubs, Meadow Brook, Loudoun 230 kV
  - Welton Spring
- SVC Optimization
  - Juniata, T157, Mt Storm

Outstanding 2015 Work

- 2015 N-1-1 Voltage Studies
  - In-progress

- Continuing to test upgrade alternatives in the ComED zone

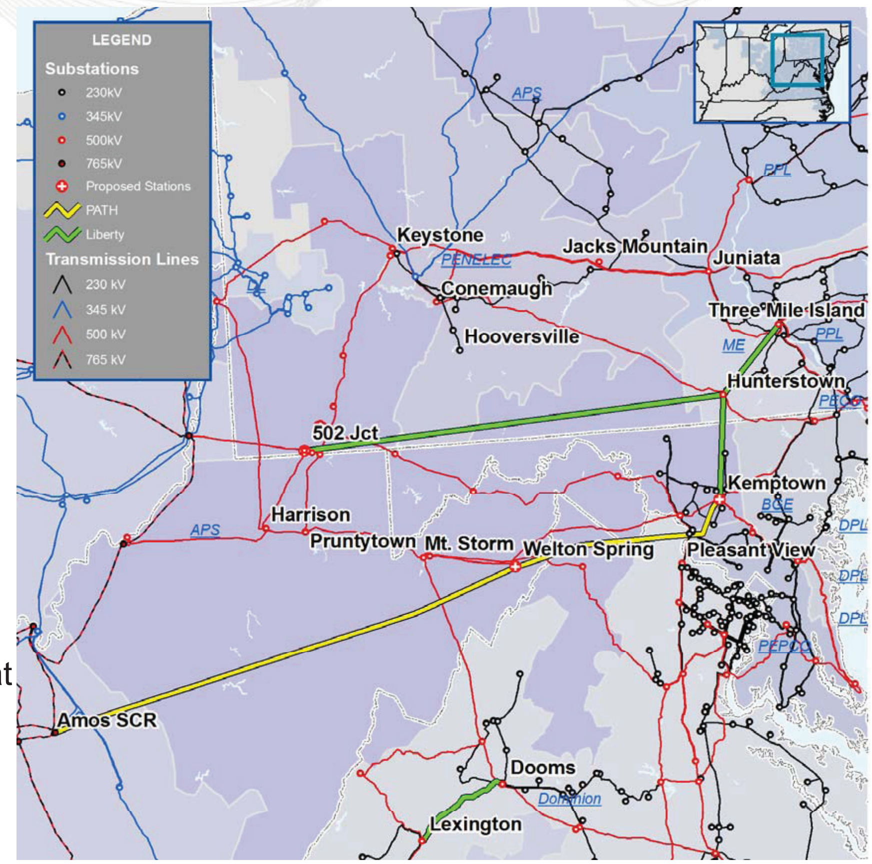
MAAC Alternative Analysis Update

Revised Liberty / LS Power

- 502J – Hunterstown 500 kV (includes 50% series compensation)
- Hunterstown – TMI 500 kV
- Hunterstown – Kemptown 500 kV
- Lexington – Dooms 500 kV

PATH

- Amos – Welton Spring – Kemptown
- Includes baseline reactive upgrades of 1000 MVAR shunt and 500 MVAR SVC at Welton Spring and a 250 MVAR shunt at Kemptown 500kV



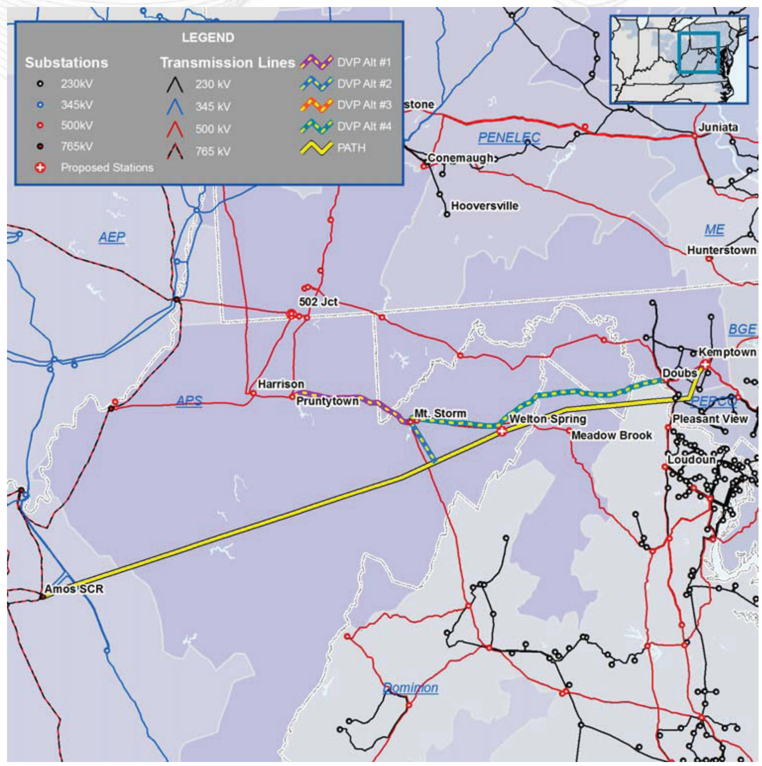
MAAC Alternative Analysis

Dominion Alternative #1
- Rebuild Mt. Storm – Doubs
- 50% series compensation on Meadow Brook end of Trail
- Rebuild Mt. Storm – Pruntytown

Dominion Alternative #2
- Rebuild Mt. Storm – Doubs
- 50% series compensation on Meadow Brook end of Trail
- Build a portion of PATH stopping at Mt. Storm (requires a new 765/500 kV transformer)

Dominion Alternative #3
- Rebuild Mt. Storm – Doubs
- 50% series compensation on Meadow Brook end of Trail
- Build a portion of PATH stopping at Welton Spring (requires new 765/500 kV transformer)

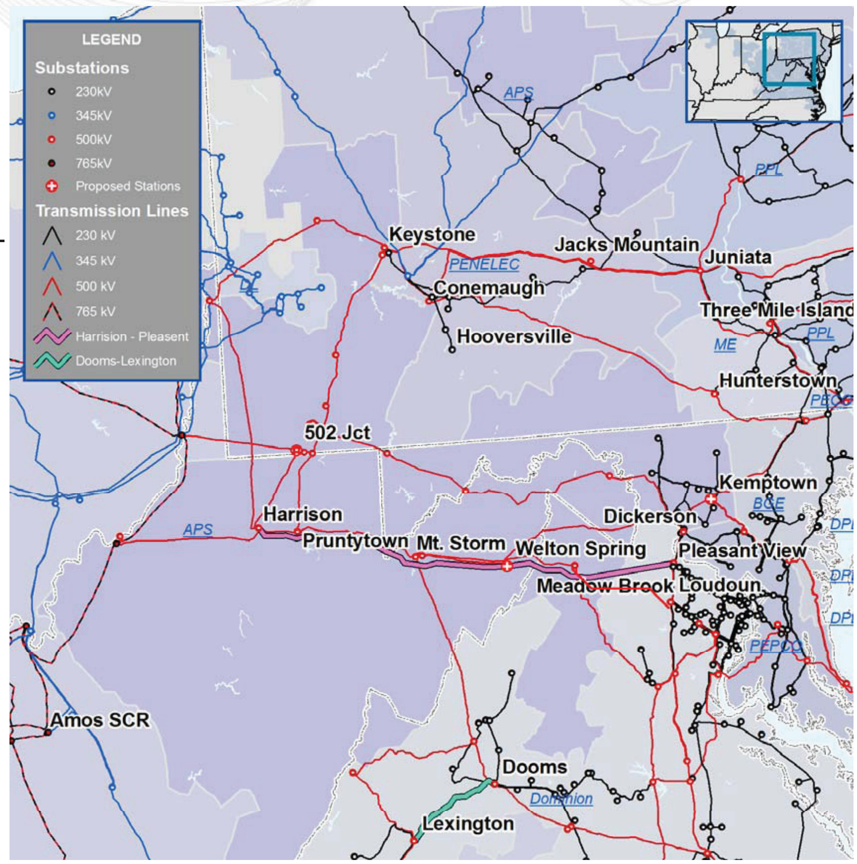
Dominion Alternative #4
- Rebuild Mt. Storm – Doubs
- Build PATH proposal



* All Dominion alternatives include 900 MVAR SVC’s at Loudoun 230 kV and T157 Tap 500 kV and 900 MVAR of static capacitors at other locations

Harrison – Dickerson Alternative

- Harrison – Dickerson New 500kV AC Line
- New Dickerson 500/230 kV Station
- Series Comp on Meadow Brook – Loudoun
- Lexington – Dooms 500 kV



Alternative Comparison - Thermal

- PATH, Revised Liberty, Harrison Dickerson and Dominion Alternative 4 (which includes the full PATH project) all resolve the thermal violations through the 15 year planning horizon

- FCITC analysis showed PATH to be the most robust alternative for transfers between various areas
  - Harrison to Dickerson was significantly less than PATH or Liberty considering transfers between various areas

- PATH reduces real power losses on the system more than any of the alternatives
  - Harrison – Dickerson losses were at least 100 MW greater than PATH (190 MW for MAAC load deliverability scenario)

Alternative Comparison - Reactive

- Reactive only alternatives not effective beyond 2016
- Harrison – Dickerson and partial Liberty (502 Junction – Hunterstown) not as effective as full Liberty project or PATH project
- PATH project and Liberty project comparable from a reactive perspective
- For MAAC load deliverability scenario, PATH project reduces reactive losses by more than 1000 MVAR compared to Liberty.

Liberty Construction Feasibility Study

- Full report posted with the materials for today's meeting
- Study evaluated multiple potential routes for each line based on criteria such as:
  – length, state and federal land crossed, potentially displaced residences and businesses, road, railway, streams, and transmission line crossings, and proximity to sites listed on the National Register of Historic Places (NRHP)
- A single route for each segment was selected and cost estimates and overall project schedule were developed

- Line Segments
  - 502 Junction to Hunterstown
    - 169 miles
    - Selected route located in Pennsylvania and Maryland
  - Hunterstown to Three Mile Island
    - 35 miles
    - Located in Pennsylvania
  - Hunterstown to Kemptown
    - 39 miles
    - Located in Pennsylvania and Maryland
  - Lexington to Dooms
    - 40.4 miles
    - Located in Virginia

- Total line length for all segments – 283.4 miles
- Estimated cost - $ 2.01 Billion to $2.53 Billion
  - Includes substation engineering and construction for 7 substations, transmission line engineering and construction, land acquisition, routing, siting, permitting, wetland mitigation, construction management and contingency
- Estimated project duration – 7 years
  - Critical path items include routing, siting, NEPA approval, land acquisition, line and substation construction

Other Considerations

- PATH total line length approximately 277 miles
  - 121 miles existing ROW adjacent other facilities
  - 156 miles new ROW
- Liberty total line length approximately 283 miles
  - All new ROW (some segments may parallel existing facilities)
- Cost estimates
  - PATH cost estimate (by PATH) = $2.10 Billion
  - Liberty cost estimate (by LS Power) = $1.336 Billion
  - Liberty cost estimate (by PJM consultant) = $ 2.01 - $2.53 Billion
- Schedule
  - PATH has been working on siting, permitting and engineering since 2007 and can be placed in-service by June 1, 2015
  - Liberty estimated project duration is 7 years

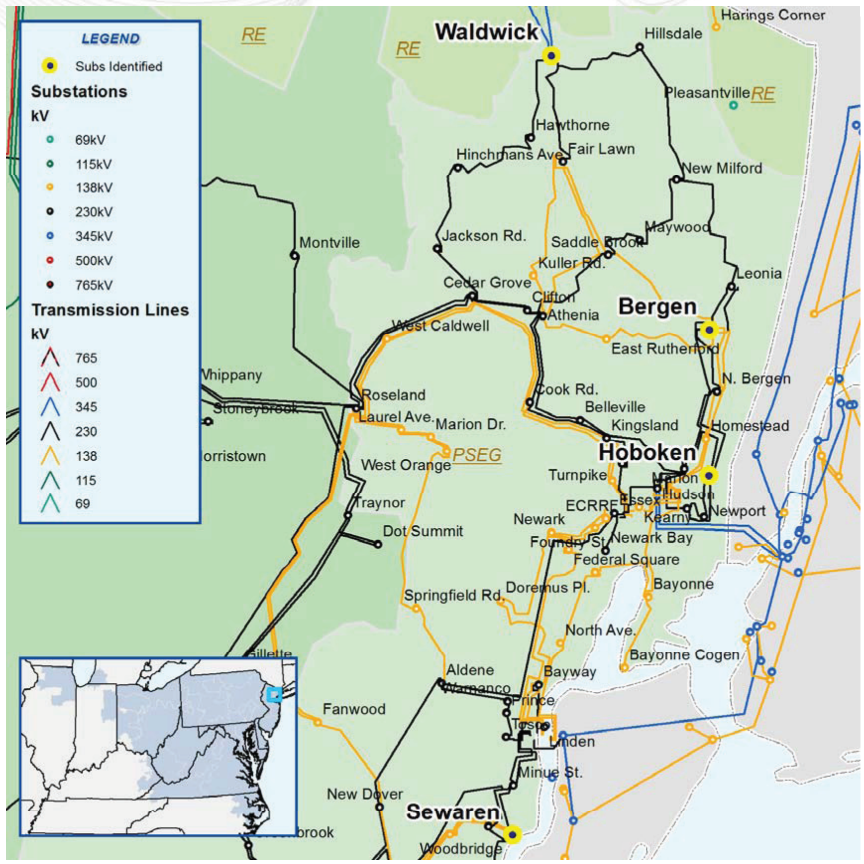
- PJM staff will be recommending to the PJM Board of Managers to continue with the PATH project as the preferred alternative

- The required in-service date for the project is June 1, 2015

Supplemental Projects

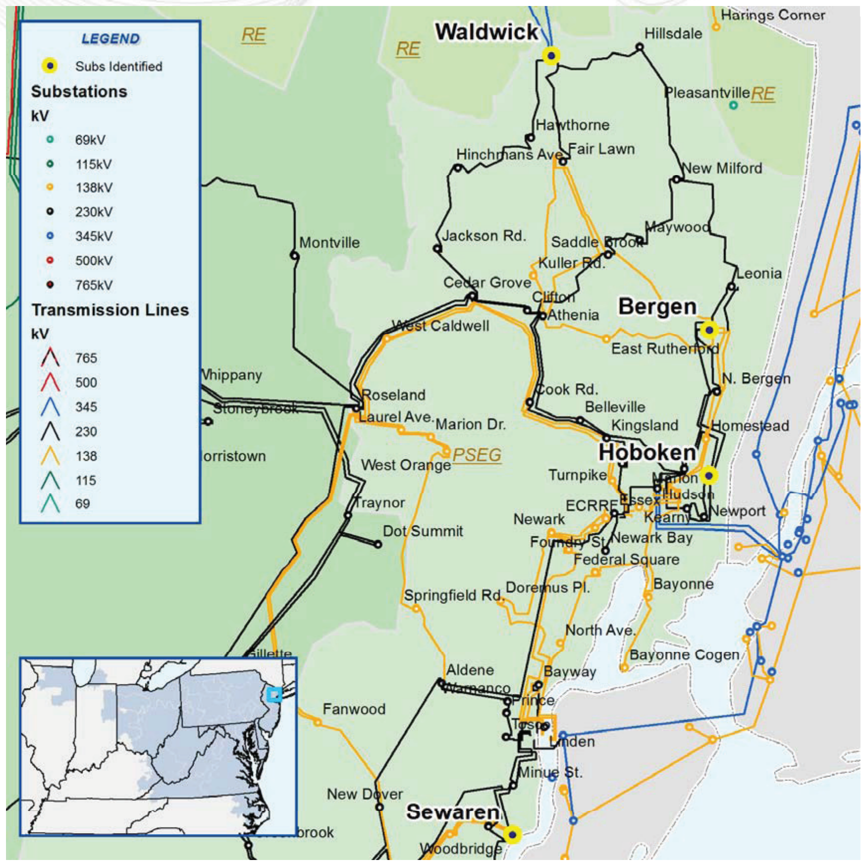
PSEG Transmission Zone

- At Bergen, existing distribution transformers currently fed from the 138 kV system will be moved to the 230 kV system
- Expected IS Date: 6/1/2013



PSEG Transmission Zone

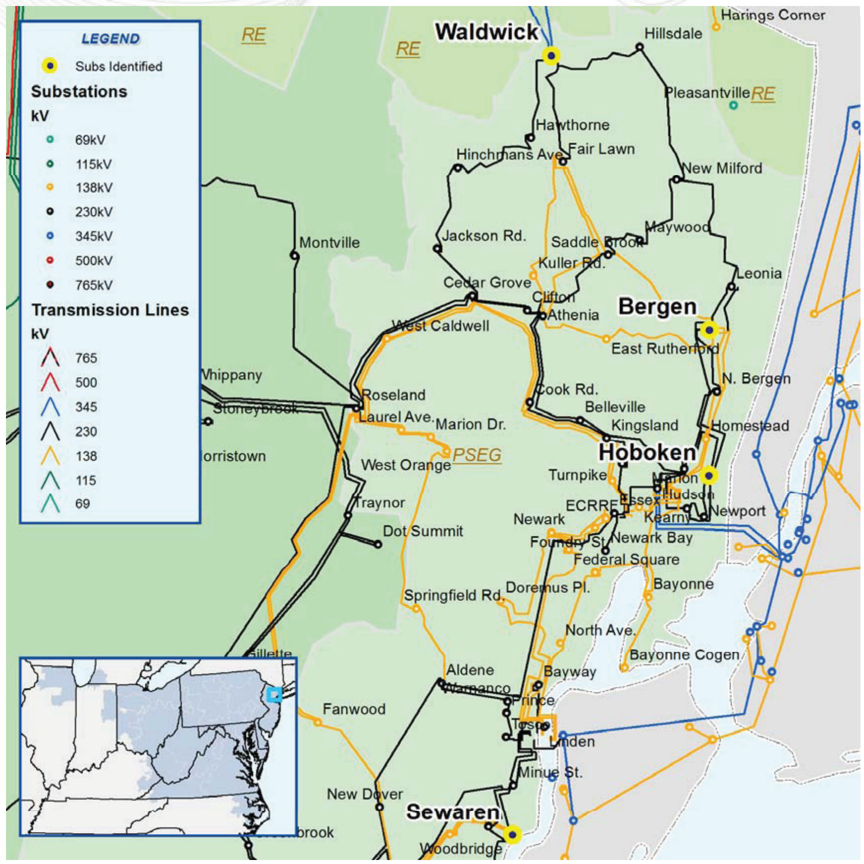
- Sewaren 230/138 kV transformer oil leakage
- Proposed Solution: Replace the Sewaren 230/138 kV transformer, add two 230 kV and one 138 kV breakers at Sewaren
- Expected IS Date: 6/1/2013



PSEG Transmission Zone

- Waldwick 345 kV breakers have gas leakage problems and the circuit switchers are defective due to age and are no longer produced
- Proposed Solution:

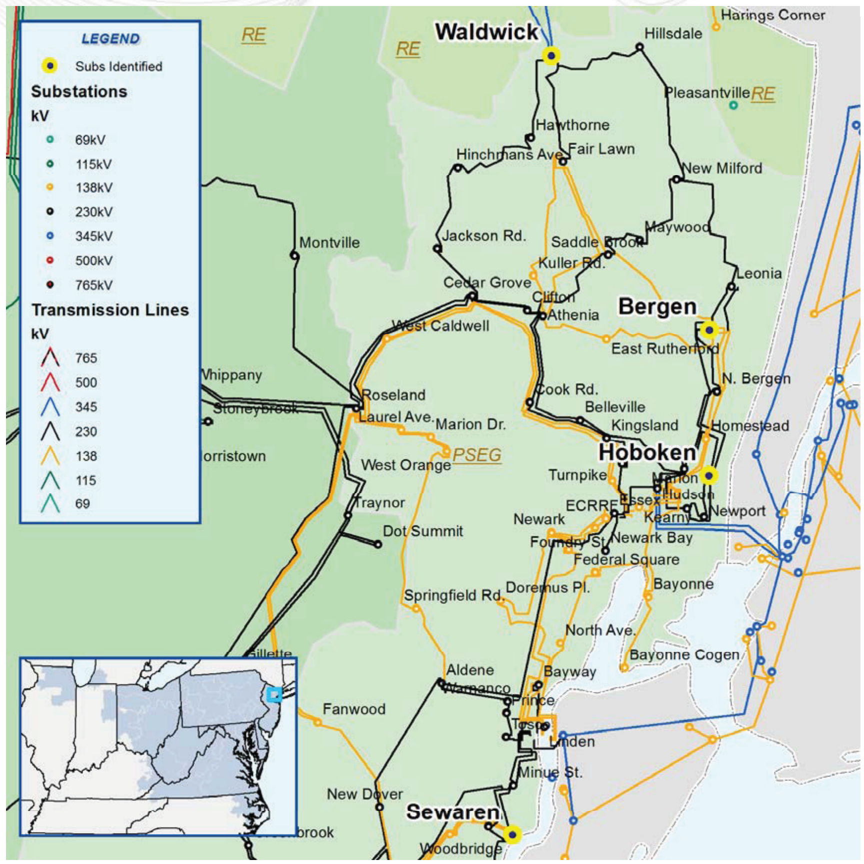
  Replace the four existing Waldwick 345 kV breakers and reconfigure the substation to breaker and half scheme by adding four new 345 kV breakers
- Expected IS Date: 6/1/2011



PSEG Transmission Zone

- Hoboken 230 kV substation has reliability issue due to circuit switcher performance leading to frequent outages
- Proposed Solution:

  Replace the existing Hoboken circuit switchers with GIS bus due to space limitation
- Expected IS Date: 6/1/2013



Market Efficiency Update

- Projects being evaluated in COMED area to address future congestion.
  - BCP Transmission Project submitted by LS Power for new single 345 kV line from Byron to Cherry Valley to Pleasant Valley.
    - Variations being considered to maximize Benefit/Cost
    - Variations of BCP project currently include Cherry Valley-Pleasant Valley 345 KV, Byron-Pleasant Valley 345 kV, and Byron-Wayne 345 kV.
  - LaSalle Transmission Project submitted by LS Power for new single or double 345 kV line from Pontiac Midpoint to Reynolds to Dumont (V4-026) with ISD of 6/1/2014.
  - La Fayette Transmission Project submitted by LS Power for new single or double 345 kV line from Quad Cities to Kewanee to Pontiac Midpoint to Reynolds to Dumont along with 345/138 kV transformers at Kewanee station with ISD of 6/1/2015.
  - Various configurations of LaSalle and LA Fayette Projects

- The 10-year analysis on 2010/11 Stage 1A ARRs resulted in infeasibility on the following facilities. Upgrades will be evaluated for inclusion into the PJM RTEP.
  - 155 Nelson 345 KV 15502 Line (Nelson to Electric Junction 345 KV line)
  - 12204 138 KV 12204 2 Line (Marengo to Pleasant Valley 138 KV line)
  - 151 Wood 138 KV 12205 2 (Woodstock to Marengo 138 KV line)

- The final Market Efficiency Upgrades will be evaluated against the 10-year ARR analysis to see if upgrades fix future ARR infeasibility.

Review Issues Tracking

Email RTEP@pjm.com with any comments