STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

ILLINOIS POWER COMPANY	)	
	)	
Proposed revisions to delivery services	)	**01-0432**
Tariff sheets and other sheets.	)	

ILLINOIS POWER COMPANY'S

PROPOSED ORDER

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By the Commission:

I. INTRODUCTION

On June 1, 2001, Illinois Power Company ("Illinois Power," "IP" or "Company") filed the following new and revised delivery services tariff sheets and other tariff sheets with the Commission:

Ill. C. C. No. 31 (Schedule for Rates for Electric Service)

Fourteenth Revised Sheet No. 1 (Table of Contents – Page 1 of 2)
Canceling Thirteenth Revised Sheet No. 1
Twenty-second Revised Sheet No. 2 (Table of Contents – Page 2 of 2)
Canceling Twenty-first Revised Sheet No. 2
Fifth Revised Sheet Nos. 3 & 6 (Standard Terms and Conditions – Pages 1 & 15 of 20)
Canceling Fourth Revised Sheet Nos. 3 & 6
Second Revised Sheet Nos. 3.1, 5.1 & 6.1 (Standard Terms and Conditions – Pages 2, 5 & 16 of 20)
Canceling First Revised Sheet Nos. 3.1, 5.1 & 6.1
Tenth Revised Sheet No. 4 (Standard Terms and Conditions – Page 3 of 20)
Canceling Ninth Revised Sheet No. 4
Fourth Revised Sheet No. 5 (Standard Terms and Conditions – Page 4 of 20)
Canceling Third Revised Sheet No. 5
Original Sheet Nos. 5.2 – 5.10 & 6.3 – 6.5 (Standard Terms and Conditions – Pages 6-14 & 18-20 of 20)
First Revised Sheet No. 6.2 (Standard Terms and Conditions – Page 17 of 20)
Canceling Original Sheet No. 6.2
Third Revised Sheet Nos. 56.0001 & 56.0002 (Service Classification 110, Table of Contents – Pages 1-2 of 3)
Canceling Second Revised Sheet Nos. 56.0001 & 56.0002
Second Revised Sheet No. 56.0003 (Service Classification 110, Table of Contents – Page 3 of 3)
Canceling First Revised Sheet No. 56.0003
Third Revised Sheet Nos. 56.0004 & 56.008 (Service Classification 110 – Pages 1 & 5 of 34)
Canceling Second Revised Sheet Nos. 56.0004 & 56.0008
Second Revised Sheet Nos. 56.0005 - 56.0007 & 56.0009 - 56.0010 (Service Classification 110 – Pages 2-4 & 6-7 of 34)
Canceling First Revised Sheet Nos. 56.0005 - 56.0007 & 56.009 - 56.0010
Third Revised Sheet Nos. 56.0011 - 56.0012 & 56.0014 (Service Classification 110 – Pages 8-9 & 11 of 34)
Canceling Second Revised Sheet Nos. 56.0011 - 56.0012 & 56.0014

Second Revised Sheet Nos. 56.0013, 56.0015 - 56.0017 & 56.0019 - 56.0025 (Service Classification 110 – Pages 10, 12-14 & 16-22 of 34)

Canceling First Revised Sheet Nos. 56.0013, 56.0015 - 56.0017 & 56.0019 - 56.0025

Fourth Revised Sheet Nos. 56.0018 & 56.0034 (Service Classification 110 – Pages 15 & 31 of 34)

Canceling Third Revised Sheet Nos. 56.0018 & 56.0034

Second Revised Sheet Nos. 56.0027, 56.0029, 56.0031, 56.0036 & 56.0037 (Service Classification 110–Pages 24, 26, 28, 33 & 34 of 34)

Canceling First Revised Sheet No. 56.0027, 56.0029, 56-0031, 56.0036 and 56.0037

Third Revised Sheet Nos. 56.0026, 56.0028, 56.0030, 56.0032, 56.0033 & 56.0035 (Service Classification 110 – Pages 23, 25, 27, 29, 30 & 32 of 34)

Canceling Second Revised Sheet Nos. 56.0026, 56.0028, 56.0030, 56.0032, 56.0033 & 56.0035

Second Revised Sheet Nos. 56.0037.1, 56.0037.4, 56.0037.6 - 56.0037.8 & 56.0037.12 (Cancellation Sheets)

Canceling First Revised Sheet Nos. 56.0037.1, 56.0037.4, 56.0037.6 - 56.0037.8 & 56.0037.12

First Revised Sheet Nos. 56.0037.2 - 56.0037.3, 56.0037.5, 56.0037.9 - 56.0037.11 & 56.0037.13 (Cancellation Sheets)

Canceling Original Sheet Nos. 56.0037.2 - 56.0037.3, 56.0037.5, 56.0037.9 - 56.0037.11 & 56.0037.13

Second Revised Sheet Nos. 56.0038 & 56.0039 (Service Classification 150, Table of Contents–Pages 1-2 of 2)

Canceling First Revised Sheet Nos. 56.0038 & 56.0039

Second Revised Sheet Nos. 56.0040 & 56.0042 – 56.0047 (Service Classification 150 – Pages 1 & 3-8 of 22)

Canceling First Revised Sheet Nos. 56.0040 & 56.0042 – 56.0047

Third Revised Sheet Nos. 56.0041, 56.0048, 56.0050, 56.0052 - 56.0053 & 56.0056 (Service Classification 150 – Pages 2, 9, 11, 13-14 & 17 of 22)

Canceling Second Revised Sheet Nos. 56.0041, 56.0048, 56.0050, 56.0052 - 56.0053 & 56.0056

Second Revised Sheet Nos. 56.0049, 56.0051, 56.0054 – 56.0055 & 56.0057 - 56.0061 (Service Classification 150 – Pages 10, 12, 15-16 & 18-22 of 22)

Canceling First Revised Sheet Nos. 56.0049, 56.0051, & 56.0054 - 56.0055 & 56.0057 – 56.0061

Second Revised Sheet Nos. 56.0062 - 56.0067 (Service Classification 150, Appendix 1 – Table of Contents and Pages 1-3 of 27)

Canceling First Revised Sheet Nos. 56.0062 - 56.0067

First Revised Sheet Nos. 56.0067.1- 56.0067.6 (Service Classification 150, Appendix 1 – Pages 4 – 9 of 27)

Canceling Original Sheet Nos. 56.0067.1 – 56.0067.6

Second Revised Sheet Nos. 56.0068 - 56.0071 (Service Classification 150, Appendix 1 – Pages 10-13 of 27)
    Canceling First Revised Sheet Nos. 56.0068 - 56.0071
Third Revised Sheet Nos. 56.0072 - 56.0085 (Service Classification 150, Appendix 1 – Pages 14-27 of 27)
    Canceling Second Revised Sheet Nos. 56.0072 – 56.0085
Third Revised Sheet Nos. 56.0086 – 56.0089 (Service Classification 150, Appendix 2 - Pages 1-4 of 4)
    Canceling Second Revised Sheet Nos. 56.0086 – 56.0089
Second Revised Sheet Nos. 56.0095 & 56.0101 - 56.0112 (Cancellation Sheets)
    Canceling First Revised Sheet Nos. 56.0095 & 56.0101 - 56.0112
First Revised Sheet Nos. 56.0096 – 56.0100 & 56.0113 - 56.0149 (Cancellation Sheets)
    Canceling Original Sheet Nos. 56.0096 – 56.0100 & 56.0113 – 56.0149
Original Sheet Nos. 76.6.1 –76.6.3 (Rider ISS – Interim Supply Service)
Sixth Revised Sheet Nos. 88.1 – 88.2 & 88.5 (Rider PPO – Pages 1-2 & 5 of 13)
    Canceling Fifth Revised Sheet Nos. 88.1 – 88.2 & 88.5
Fifth Revised Sheet Nos. 88.3 & 88.7 – 88.8 (Rider PPO – Pages 3 & 7-8 of 13)
    Canceling Fourth Revised Sheet Nos. 88.3 & 88.7 - 88.8
Fourth Revised Sheet Nos. 88.4 & 88.6 (Rider PPO – Pages 4 & 6 of 13)
    Canceling Third Revised Sheet Nos. 88.4 & 88.6
Third Revised Sheet Nos. 88.9 & 88.11 (Rider PPO – Pages 9 & 11 of 13)
    Canceling Second Revised Sheet Nos. 88.9 & 88.11
Second Revised Sheet No. 88.10 (Rider PPO – Page 10 of 13)
    Canceling First Revised Sheet No. 88.10
Original Sheet Nos. 88.12 - 88.13 (Rider PPO – Pages 12 & 13 of 13)
Original Sheet Nos. 88.14 – 88.15 (Rider PRS – Partial Requirements Service)
Third Revised Sheet Nos. 95.1 – 95.5 (Rider TC – Pages 1-5 of 15)
    Canceling Second Revised Sheet Nos. 95.1 – 95.5
Fourth Revised Sheet No. 95.6 (Rider TC – Page 6 of 15)
    Canceling Third Revised Sheet No. 95.6
Third Revised Sheet No. 95.7 (Rider TC – Page 7 of 15)
    Canceling Second Revised Sheet No. 95.7
Fourth Revised Sheet Nos. 95.8 – 95.9 (Rider TC – Pages 8-9 of 15)
    Canceling Third Revised Sheet Nos. 95.8 – 95.9
Third Revised Sheet Nos. 95.10 – 95.14 (Rider TC – Pages 10-14 of 15)
    Canceling Second Revised Sheet Nos. 95.10 – 95.14
Original Sheet No. 95.14.1 (Rider TC – Page 15 of 15)
Third Revised Sheet Nos. 95.15 – 95.20 (Rider TC, Appendix 1 – Pages 1-6 of 7)
    Canceling Second Revised Sheet Nos. 95.15. – 95.20
Original Sheet No. 95.20.1 (Rider TC, Appendix 1 – Page 7 of 7)
Third Revised Sheet No. 95.21 (Rider TC, Appendix 2)
    Canceling Second Revised Sheet No. 95.21

Ill. C. C. No. 33 (Rules, Regulations and Conditions Applying to Electric Service)

Fourth Revised Sheet Nos. 1 - 2 (Table of Contents and Section 1 – Page 1 of 3)

Canceling Third Revised Sheet Nos. 1 - 2
Third Revised Sheet No. 2.1 (Section 1 – Page 2 of 3)
Canceling Second Revised Sheet No. 2.1
Fifth Revised Sheet No. 3 (Section 1 – Page 3 of 3)
Canceling Fourth Revised Sheet No. 3
Third Revised Sheet No. 3.1 (Cancellation Sheet)
Canceling Second Revised Sheet No. 3.1
Second Revised Sheet No. 3.2 (Section 2 – Page 1 of 3)
Canceling First Revised Sheet No. 3.2

Illinois Power filed the delivery service tariff sheets and other tariff sheets, hereinafter referred to as the "Filed Rate Schedule Sheets," in which it proposed to revise its delivery services tariff ("DST") sheets to set forth the rates, terms and conditions under which delivery services will be provided to both residential and non-residential customers, as well as the terms and conditions under which IP will offer other, related services, to be effective July 16, 2001.

Based on its review of the Filed Rate Schedule Sheets, the Commission concluded that it should enter upon a hearing concerning the propriety of the proposed revisions to the delivery services tariffs sheets and the other tariff sheets, and that pending the hearing and the decision thereon, the proposed new and revised delivery services tariff sheets and other tariff sheets should not go into effect. Accordingly, on June 6, 2001, the Commission issued a Suspension Order initiating this docket and suspending the effectiveness of the Filed Rate Schedule Sheets for a period of 105 days beginning with July 16, 2001, to and including October 28, 2001. On October 24, 2001, the Commission issued a Resuspension Order further suspending the effective date of the Filed Rate Schedule Sheets to and including April 28, 2002.

Petitions to intervene were filed by A.E. Staley Manufacturing Company, Air Products & Chemicals Company, Archer-Daniels-Midland Company, Bunge North America, Inc., Cargill, Inc., Caterpillar, Inc., Continental General Tire Company, Granite City Steel Company, Olin Corporation and Spectrulite Consortium, Inc., as the Illinois Industrial Energy Consumer ("IIEC"); the Association of Illinois Electric Cooperatives; the Attorney General on behalf of the People of the State of Illinois ("AG"); Central Illinois Light Company ("CILCO"); the Citizens Utility Board ("CUB"); Enron Energy Services, Inc.; MidAmerican Energy Company ("MEC"); Midwest Energy Alliance, L.L.C.; and the National Energy Marketers Association. All of these petitions to intervene were granted by the Administrative Law Judge ("ALJ").

Pursuant to notice duly given in accordance with the rules and regulations of the Commission, a prehearing conference in this matter was held before a duly authorized ALJ of the Commission at its offices in Springfield, Illinois, on June 27, 2001. A second prehearing conference was held on November 14, 2001. Thereafter, evidentiary hearings were held in this matter at the Commission's offices in Springfield on November 26-30, 2001. Appearances were entered at one or both prehearing conference and at one or more of the evidentiary hearings by counsel on behalf of IP, the AG, CILCO, CUB, IIEC, MEC and the Staff of the Commission ("Staff"). At the conclusion of the November 30, 2001, hearing, the record was marked "Heard and Taken."

The following witnesses submitted testimony on behalf of IP in this case: Peggy E.

Carter, IP's Vice President and Controller; John P. Barud, Regional Director for the Metro North Region of IP; Daniel L. Mortland, Director of Regulated Pricing and Costing Services; Jacqueline K. Voiles, Director of Delivery Services; Leonard M. Jones, Director – Business Planning & Forecasting; Dale L. Holtzscher, Manager of the Retail Electric Supplier Business Center; Karen R. Althoff, Senior Regulatory Specialist in the Business Development Services department of IP; Patricia K. Spinner, Senior Specialist in the Business Development Services department of IP; Mark J. Peters, Manager – Energy Resources; and Ellen R. Hearn, Senior Human Resources Generalist in the Human Resources Department of IP.

The following witnesses submitted testimony on behalf of Staff in this case: Dianna L. Hathhorn, an Accountant in the Accounting Department of the Financial Analysis Division of the Commission; Mary H. Everson, an Accountant in the Accounting Department of the Financial Analysis Division; Bonita A. Pearce, an Accountant in the Accounting Department of the Financial Analysis Division; Rochelle Langfeldt, a Financial Analyst in the Finance Department of the Financial Analysis Division; Peter Lazare, a Senior Economic Analyst in the Rates Department of the Financial Analysis Division; Cheri L. Harden, a Rate Analyst in the Rates Department of the Financial Analysis Division; Eric P. Schlaf, an Economist in the Energy Division; David A. Borden, of the Policy Section of the Energy Division; and Howard J. Haas, Senior Economist in the Policy Section of the Energy Division.

The following witnesses submitted testimony on behalf of intervenors in this case: on behalf of CUB and the AG, Lee Smith, Senior Economist and Managing Consultant at LaCapra Associates, and David J. Effron, a certified public accountant and consultant specializing in utility regulation; on behalf of IIEC, Robert R. Stephens and Nicholas Phillips, Jr., both consultants with the firm of Brubaker & Associates, Inc.; and on behalf of MEC, George Phillips, Manager of Regulatory Support in the Marketing and Sales Division of MEC. In addition to the foregoing witnesses, IP submitted the testimony of Paul R. Moul, Managing Consultant, P. Moul & Associates, and IIEC submitted the testimony of Michael Gorman, consultant with Brubaker & Associates, Inc., both on the subject of cost of common equity; however, in light of the settlement reached on cost of capital issues, as discussed later in this Order, the testimony of Messrs. Moul and Gorman was not offered into evidence by these parties.

Initial briefs and reply briefs were filed in this docket buy IP, CUB/AG, IIEC, MEC and Staff. IP and ___ filed proposed orders. An ALJ's Proposed Order was served on the parties. Briefs on exceptions and briefs in reply to exceptions were filed by IP, CUB/AG, IIEC, MEC and Staff. These filings have been considered by the Commission in reaching its conclusions in this proceeding.

II. REVENUE REQUIREMENTS

A. Test Year

Illinois Power proposed a historical test year consisting of the twelve months ended December 31, 2000, with adjustments for known and measurable changes and other pro forma adjustments. No party opposed the use of a historical 2000 test year. (IP Init. Br., p. 3)

B. Distribution Rate Base

1. Overview of IP's Proposed Distribution Rate Base

Illinois Power proposes the following distribution rate base (Rev. IP Ex. 3.24) (See also IP Init. Br., p. 3):

Item	Amount (000)
Plant in Service	
Distribution Plant	$1,472,356.0
General Plant	201,730.0
Intangible Plant	70,714.0
Accum. Depreciation – Distribution	(577,623.0)
Accum. Depreciation – General	(37,210.0)
Accum. Depreciation – Intangible	(54,664.0)
Net Plant in Service	$1,075,303.0
Adjustments to Rate Base	
Land Held for Future Use	---
CWIP – Not including AFUDC	5,592.0
Dep. Res. – Contrib. Elec. Distrib.	2,870.0
Working Capital	9,960.0
Reserve for Deferred Income Taxes	(180,948.0)
Customer Deposit Balance	(2,044.0)
Customer Advances for Construction	(1,032.0)
Pre-1971 Investment Tax Credits	(538.0)
Total Adjustments to Rate Base	(166,140.0)
Total Rate Base	$ 909,163.0

2. Uncontested Adjustments

Illinois Power's proposed rate base incorporates a number of adjustments that were proposed by the Company and not opposed by any other party, as well as a number of adjustments that were proposed by other parties and accepted by the Company. The following paragraphs summarize the uncontested adjustments. (IP Init. Br., p. 4)

Load research project. The rate base includes capital investment that has been incurred for acquisition and installation of specialized load research meters to collect data, and other infrastructure costs, for a load research program. The data collected will be used to develop load profiles specific to the IP service area and for other distribution planning purposes. This adjustment increases rate base by $1,554,000. (IP Ex. 6.1, p. 28; IP Ex.6.5; IP Exs. 1.65, 1.67, 1.75; Rev. IP Ex. 3.24, p. 1, col. (5)) (IP Init. Br., p. 4)

FAS 109 Gross-up. In order to keep the rate base neutral with respect to FAS109-related deferred income taxes, IP removed FAS 109-related gross-ups for net-of-tax AFUDC in utility plant in service from the balances in Accounts 101 and 106. This adjustment reduces rate base by $1,424,000. (IP Ex. 1.1, pp. 10-11; IP Exs. 1.6, 1.65; Rev. IP Ex. 3.24, p. 1, col. (6)) (IP Init. Br., p. 4)

CWIP transferred to Utility Plant in Service. At December 31, 2000, IP's Construction Work in Progress ("CWIP") accounts included dollars for projects which had already been completed and placed in service, but not yet transferred from the CWIP accounts to the applicable plant in service account. This adjustment recognizes these amounts as plant in service. The adjustment increases rate base by $7,840,000. (IP Ex. 1.1, p. 11; Corrected Rev. IP Ex. 1.6; IP Exs. 1.65, 1.67, 1.75; Rev. IP Ex. 3.24, p. 1, col. (7)) (IP Init. Br., p. 4)

Facilities no longer in use. IP has closed or is closing a number of facilities that were included in plant in service accounts as of December 31, 2000. These facilities include a total of 12 service area buildings and other buildings throughout IP's service area. This adjustment removes the investment in these facilities, and the related accumulated depreciation and deferred tax reserve, from rate base. The adjustment reduces rate base by $157,000. (IP Ex. 1.1, pp. 11-12; IP Ex. 2.1, p. 19; IP Exs. 1.8, 1.29, 1.65, 1.67, 1.75; Rev. IP Ex. 3.24, p. 1, col. (8)) (IP Init. Br., p. 5)

Unamortized pre-1971 Investment Tax Credits ("ITC"). This adjustment reduces the amount of unamortized pre-1971 ITC and thus increases rate base. This adjustment, which recognizes additional amortization of pre-1971 ITC from January 1, 2001 through September 30, 2001, was implemented in connection with recognizing additional accumulated depreciation for the same period on plant in service at December 31, 2001, as proposed by CUB/AG witness Effron. This adjustment increases rate base by $26,000. (Rev. IP Ex. 3.24, p. 3, col. (26)) (IP Init. Br., p. 5)

Cash working capital. IP's proposed rate base includes an allowance for cash working capital.[1] IP developed the cash working capital component by performing a lead/lag study, using a methodology similar to the one presented and adopted in IP's 1999 DST case, Dockets 99-0120 & 99-0134 (Cons.) ("1999 DST Case") (IP Ex. 1.1, pp. 12-13) During the course of the case, IP made revisions to the cash working capital study to take into account revisions and adjustments to various revenue, expense and return items that are components of the study. In addition, CUB/AG witness Effron proposed two substantive adjustments to IP's cash working capital study; IP accepted both of these adjustments, although it implemented one of them somewhat differently than Mr. Effron had proposed. (GCI Ex. 2.0, pp. 25-27; IP Ex. 1.34, pp. 22-25) Mr. Effron accepted IP's implementation of his adjustment. (GCI Ex. 4.0, p. 5; Tr. 402-03) As adjusted for the Effron adjustment and other revisions, the cash working capital component included in rate base is $3,087,000. (Rev. IP Ex. 3.24, p. 1, col. (9)) (IP Init. Br., pp. 5-6)

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[1] The "Working Capital" component of rate base shown in the table in Section II.B.1 above consists of (1) a 13-month average balance of materials and supplies, less the average balance of the related accounts payable (IP Ex. 1.1, p. 6) plus (2) the cash working capital allowance.

3. Contested Adjustments

This section of the Order discusses the proposed adjustments that remain disputed.

a. Post-test year plant additions

(1) IP's Position

Illinois Power proposes adjustments to the December 31, 2000 balances of plant in service, accumulated provision for depreciation and reserve for deferred taxes to reflect capital additions that will be placed in service subsequent to December 31, 2000. The projects included in the proposed adjustment consist of (1) additions to distribution plant, (2) additions to G&I plant that are being placed in service exclusively or predominantly for use by IP's Energy Delivery business group, and (3) additions to G&I plant that support corporate overhead functions. All of the proposed additions to G&I plant, including those being placed in service exclusively or primarily for use by the Energy Delivery business group, have been allocated between the gas and electric utilities, and the electric portion then allocated to the electric distribution function, on the same basis, resulting in 57.9% of the total cost of each of the G&I plant additions being allocated to electric distribution. (See IP Exs. 1.64, 2.19 and 2.20) The individual distribution plant additions with costs in excess of $500,000, and the G&I plant additions to be used by the Energy Delivery business group, were described by IP witness Barud. (See IP Exs. 2.8 and 2.15 and Corrected Rev. IP Ex. 2.10) The corporate G&I capital additions projects (item (3) above) were described and justified by IP witness Carter. (See Corrected Rev. IP Ex. 1.5) All of the capital additions supported by these witnesses have planned in-service dates on or before June 2002; by the close of the record in this case, many of the projects had in fact been completed. (See, e.g., IP Exs. 2.8 and 2.19 and AG Cross Ex. 1) (IP Init. Br., pp. 6-7)

In its rebuttal testimony, IP accepted Staff witness Everson's limitation on capital additions to those projects that had received funding approval from IP management. (IP Ex. 2.13, pp. 1-2) In its surrebuttal testimony, IP presented information on its actual expenditures as of September 30, 2001, and remaining expenditures, on projects that had received funding approval as of September 30. (IP Exs. 1.64, 2.18, 2.19, 2.20) IP notes that Ms. Everson reviewed this information (including supporting information provided through data requests) and concluded that the capital additions amounts proposed by IP for inclusion in rate base in its surrebuttal evidence are "known and measurable." (Tr. 122-124) Following are the resulting amounts of capital additions to distribution rate base, net of related retirements, that IP proposes (IP Exs. 1.64 and 2.18-2.20; IP Init. Br., p. 10):

Distribution plant additions:	$80,195,901
General plant additions for Energy Delivery:	$ 1,976,455
Intangible plant additions for Energy Delivery:	$ 1,303,082
Corporate G&I plant additions:	$10,789,000

As part of its adjustment for capital additions, IP also removed from the balances of plant in service and accumulated depreciation the net cost of facilities that have been or will be retired subsequent to December 31, 2000, as a result of placement of the capital additions into service. In addition, IP provided for accumulated depreciation and deferred taxes in respect of the capital additions in the accumulated depreciation reserve and reserve for deferred taxes, respectively. (IP Ex. 1.1, p. 12; Corrected IP Ex. 1.31, pp. 3-5; IP Exs. 1.64, 1.65, 1.67, 2.18, 2.19 and 2.20) (IP Init. Br., pp. 7-11)

IP responded to CUB/AG witness Effron's proposal that capital additions be limited to the investment in projects that had actually been placed in service as of June 30, 2001. IP noted that the reasons Mr. Effron gave for this limitation were: (1) IP was not recognizing additional accumulated depreciation subsequent to December 31, 2000, on plant in service as of that date; (2) IP was not recognizing growth in billing determinants beyond the test year; and (3) projections of expenditures through June 30, 2002, are speculative and do not represent actual expenditures. (Id., p. 10) IP stated that Mr. Effron's limitation on capital additions is arbitrary, that the reasons he advanced do not support his limitation on capital additions, and that his position should be rejected. (IP Init. Br., p. 10)

IP stated that it has increased the accumulated provision for depreciation and the reserve for deferred income taxes for the additional depreciation and deferred taxes from January 1, 2001 through September 30, 2001, relating to plant in service as of December 31, 2001. IP stated that it also adopted Mr. Effron's proposal to use an average of the actual year-end 2000 values and the forecasted year-end 2001 values (numbers of customers and kWh) for the billing determinants, rather than using the actual billing determinants for the 12 months ended December 31, 2000, as IP had originally proposed. IP stated that it expanded upon Mr. Effron's proposal, in that while he only proposed using the average of the 2000 and 2001 year-end values for residential billing determinants, IP incorporated all customer classes. (IP Ex. 6.6, pp. 3-4; Tr. 403-04) Accordingly, IP stated that Mr. Effron's first two concerns do not support his limitation on capital additions. IP further states that Mr. Effron's third concern is belied by Staff witness Everson's careful review of IP's capital additions projects, and her conclusion (which IP accepted) that those projects that have gone through IP's internal processes and procedures to the point of receiving funding approval from management meet the "known and measurable" criteria. IP points out that there is no evidence that Mr. Effron conducted any actual review of the specific capital additions projects that IP proposed for inclusion in rate base. (IP Init. Br., pp. 10-11)

IP also stated that, although the final capital additions amount proposed by IP and accepted by Ms. Everson includes remaining expenditures as of September 30, 2001 on funded projects, it also includes substantial actual expenditures as of September 30, 2001. IP notes that its proposed distribution plant capital additions amount of $92,738,667 (before reduction for related retirements) consists of $77,616,116 of actual expenditures as of September 30 and only $15,122,551 of remaining expenditures as of that date. (IP Ex. 2.18, p. 3) Similarly, the amount of general plant additions for Energy Delivery, $2,046,455 (before adjustment for retirements), consists of $1,982,099 of actual expenditures as of September 30 and $64,356 of remaining expenditures as of that date, and the amount of intangible plant additions for Energy Delivery, $1,303,082, consists of $713,744 of actual expenditures as of September 30 and $589,338 of remaining expenditures as of that date. (IP Exs. 2.19-2.20) IP states that in the aggregate, 83.6% of the foregoing capital additions were amounts actually expended as of September 30, 2001. (IP Ex. 2.17, p. 3) In summary, IP argues that CUB/AG witness Effron's proposed limitation of capital additions that can be included in rate base is based on an arbitrary cut-off date, is not based on any specific analysis of the capital additions projects that IP proposes for inclusion in distribution rate base, and does not reflect any meaningful analysis under the "known and measurable" criteria, and that none of the concerns he expressed supports his limitation. (IP Init. Br., pp. 11-12)

IP responded to CUB/AG's argument IP should have proposed a forecasted test year in order to include in rate base projects with completion dates as late as June 2002. IP stated that 83 Ill. Adm. Code 285.150(e), which sets forth criteria for post-test year capital additions where an historical test year is used in a general rate case, and which Ms. Everson used as one of the indicia of the "known and measurable" criterion, authorizes the inclusion in rate base of capital additions to be placed in service within 12 months following the filing of the proposed tariffs, which in this case would be June 2002. IOP also responded to CUB/AG's argument that Staff witness Ms. Everson ignored a cutoff date for pro forma adjustments in DST.160. IP states that CUB/AG's reliance on DST.160 supports IP's and Staff's position, not CUB/AG's position. IP notes that CUB/AG relied on the language in DST.160 that limits post-test year adjustments to those that ". . . occurred during the selected test year or are reasonably certain to occur subsequent to the selected test year but prior to January 1, 2001." IP points out that DST.160 and the related Minimum Information Requirements were developed in Docket 98-0454 to guide the electric utilities' initial DST rate case filings in 1999. IP states that the electric utilities were required by law to file those initial DST cases 210 days prior to the initial offering of delivery services (October 1, 1999), or by on or about March 1, 1999. (220 ILCS 5/16-108(a)) IP states that the "cutoff date" of January 1, 2001 was some 22 months after the date that the initial DST cases were required to be filed. IP also states that, given that a 1997 test year was used in the 1999 DST Case, the "cutoff date" of January 1, 2001 in DST.160 was 36 months after the end of the historical test year. IP concludes that, based on the use of a 2000 test year and the June 1, 2001 filing date in this case, the "cutoff date" of June 30, 2002 is within the parameters established by both 83 Ill. Adm. Code and DST.160 for post-test year adjustments to an historical test year. (IP Rep. Br., pp. 5-6)

(2) Staff's Position

Staff witness Everson reviewed IP's proposed capital additions. Ms. Everson recognized that the "known and measurable" standard, as set forth in 83 Ill. Adm. Code 285.150(e) and section DST.160 of the minimum information requirements that were established in Docket 98-0454 for use in the initial round of DST cases, are not officially applicable in this case. (Staff Ex. 2.0, p. 3) Notwithstanding, she testified that the "known and measurable" criteria outlined in these provisions are still valid for evaluating evidence of pro forma adjustments. She testified that standard auditing techniques rely on the availability of certain documents and/or testing of processes to constitute evidence of reasonable certainty of amounts. She explained that Staff routinely uses the principle underlying the criteria called "known and measurable," even when it is not specifically outlined or agreed to in a proceeding, because it provides a standard by which to evaluate pro forma adjustments that is reasonable and can be applied in a variety of situations with a variety of issues and companies. (Id., p. 4) (Staff Init. Br., pp. 4-5)

Ms. Everson testified that her review of IP's proposed capital additions involved review of the following, which IP supplied: workpapers and data request responses; information in the Company's filed testimony; copies of procedures and other internal documents that described the processes by which plant additions are identified, designed, cost estimated, approved by management, and funded by management; information that enabled Ms. Everson to determine which of its proposed plant additions projects had received funding approval from management and which had not; information that showed the actual expenditures that had been made and the remaining expenditures on those projects that had received funding approval; and access to work orders, work requests, invoices and similar documents that supported the actual and planned expenditures for the capital additions projects. (Tr. 119-121)

Ms. Everson explained that after obtaining supporting documents and review of the processes, she determined that the key element of the known and measurable criteria to apply is the funding approval by management. She testified that projects for which IP has provided evidence of a funding approval are both known and capable of being measured with reasonable certainty. (Staff Ex. 2.0, p. 5) (Staff Init. Br., p. 5)

(3) CUB/AG's Position

CUB/AG argue that IP's distribution plant additions should be limited to those additions in service as of June 30, 2001. CUB/AG also argue that IP's pro forma plant addition adjustments do not adequately acknowledge the countervailing factors of sales growth and accumulated depreciation throughout the time period that these adjustments encompass. CUB/AG argue that, by adjusting rate base for post-test year plant additions, IP is recognizing one factor that tends to increase future revenue requirements, without also recognizing factors that would have an offsetting effect. (GCI Ex. 2.0, p. 22) CUB/AG further state that IP's adjustment ignores the following three factors, with the result that the determination of rate base and the ultimate revenue requirement will be distorted: (1) growth in the accumulated depreciation reserve on plant in service; (2) growth in the balance of accumulated deferred income taxes; and (3) failure to recognize any post-test year growth in billing determinants to correspond to the additions to rate base. (See GCI Ex. 2.0, p. 22) (CUB/AG Init. Br., pp. 6-7)

With respect to the first factor they cite, CUB/AG state that IP proposes to recognize nine months of plant additions beyond the test year, while only recognizing customer growth through the end of the test year. CUB/AG state that this further accentuates the need to limit post-test year plant additions to a maximum of six months after the test year. CUB/AG indicate that if IP wanted to extend plant additions beyond this point, it should have chosen a later historic test year or a current or future test year. (CUB/AG Init. Br., pp. 8-9)

CUB/AG also dispute the use of the criterion proposed by Staff and accepted by IP for determining the amount of capital additions, namely, projects that funding has been approved for and are expected to have an in-service date before June 30, 2002. CUB/AG note that IP's proposal based on this criterion includes $15 million of projects that will have an in-service date after September 30, 2001, and that some of these projects will not be placed into service until 18 months after the test year. In addition, CUB/AG state that although Staff witness Everson's analysis was based on what adjustments met the requirements for pro forma adjustments, and as set out in Docket 98-0454, and focused on the "known and measurable" standard, she failed to take into account that the Docket 98-0454 requirements have a cutoff date for pro forma adjustments. Specifically, Section DST.160 of the Docket 98-0454 requirements limits adjustments to changes that ". . . occurred during the selected test year or are reasonably certain to occur subsequent to the selected test year but prior to January 1, 2001, and the amount of the changes are determinable." CUB/AG therefore argue that IP's proposal with respect to capital additions that includes projects being place in service through June 2002 does not meet the requirements of DST.160. (CUB/AG Init. Br., pp. 9-11) Finally, CUB/AG argue that while Ms. Everson provided an opinion regarding the stage at which plant addition becomes "known and measurable," she did not testify whether these pro forma adjustments would reflect a balanced view of extending rate base additions beyond the test year. (CUB/AG Init. Br., p. 11)

(4) Commission's Analysis and Conclusion

Based on its review of the record, the Commission concludes that the capital additions proposed by IP, consisting of expenditures as of September 30, 2001, and remaining expenditures, on projects that have received funding approval from IP management as of September 30, 2001, should be included in distribution rate base. The Commission agrees with Staff that this criterion satisfies the "known and measurable" test for including capital additions in rate base in connection with a historical test year. Further, although some of the capital additions amount represents expenditures on projects that will not be placed in service until as late as June 2002, the vast majority of the capital additions amount proposed by IP consists of actual expenditures as of September 30, 2001. The Commission rejects CUB/AG's proposal to limit capital additions only to projects actually placed in service within 6 months following the end of the test year (June 30, 2001), as arbitrary and (unlike Staff witness Everson's review) not based on a specific analysis of the projects in question. The Commission also notes that in relation to the filing date of this case (June 2001) and the end of the test year in this case (December 31, 2000), the use of June 2002 as the final cut-off date for capital additions to be placed in service is within the timing parameters indicated in DST.160 and 83 Ill. Admin. Code 285.150(e), although neither of those provisions is technically applicable to this case.

b. Accumulated depreciation on plant in service at December 31, 2000

(1) IP's Position

In connection with the inclusion in rate base of capital additions for projects that had received funding approval from management as of September 30, 2001, Illinois Power also decreased rate base by the amount of accumulated depreciation and deferred income taxes accruing from January 1, 2001 through September 30, 2001 on plant that was in service as of December 31, 2000. (IP Ex. 1.63, pp. 20-21) This adjustment decreases rate base by $31,899,000 for additional accumulated depreciation, and by $3,448,000 for additions to the reserve for deferred taxes, subsequent to December 31, 2000. (Rev. IP Ex. 3.24, pp. 2-3, cols. (24)–(25)) IP states that its recognition of accumulated depreciation and deferred taxes on plant in service as of December 31, 2000, through September 30, 2001, is consistent with its proposal (accepted by Staff) to include capital additions for projects that have received funding approval as of September 30, 2001. (IP Init. Br., pp. 12-13)

In response to CUB/AG's arguments, IP states that while its capital additions include some expenditures that will be made after September 30, 2001, on projects that will not be completed by that date, IP is not proposing, and Staff has not accepted, inclusion in rate base of all of IP's projected capital additions through June 2002. IP states that its capital additions amount consists only of actual expenditures as of September 30, 2001, and remaining expenditures, on projects that had received funding approval as of that date. IP states that if it were to include in rate base all of its capital additions projected through June 2002, the amount of the adjustment to rate base would be considerably larger than what IP has proposed. (IP Ex. 2.17, p. 3) Finally, IP notes that its capital additions amount consists predominantly of actual expenditures as of September 30, 2001. (IP Init. Br., p. 13)

(2) CUB/AG's Position

CUB/AG contend that if the Commission agrees to adjust rate base for plant additions with funding approval as of September 30, 2001, then, at a minimum, the depreciation reserve and accumulated deferred taxes for plant in service as of December 31, 2000, should be adjusted to recognize growth through the date that the last of those additions actually goes into service. CUB/AG acknowledge that IP agrees that the depreciation reserve should be adjusted to reflect growth beyond the end of the test year, consistent with the adjustment to rate base for plant additions beyond the end of the test year, but contend that IP's adjustment to the depreciation reserve does not achieve consistency between plant in service on the one hand and accumulated depreciation and deferred taxes on the other hand, because it does not recognize growth in accumulated depreciation through the date that the last of the capital additions will go into service. CUB/AG argue that this inconsistency should be rectified by allowing pro forma adjustments for plant in service through a fixed date, with pro forma adjustments for depreciation reserve growth limited to that same fixed date. (CUB/AG Init. Br., pp. 11-12)

(3) Commission's Analysis and Conclusions

The Commission adopts the adjustment to increase the accumulated reserve for depreciation associated with plant in service as of December 31, 2000, and the reserve for deferred income taxes associated with such plant, through September 30, 2001, as proposed by IP. The Commission concludes that this adjustment is consistent with the basis for including capital additions in rate base, as discussed in the preceding section of this Order. The Commission notes that this adjustment is apparently concurred in by Staff. The proposal by CUB/AG to extend the reserve for depreciation and the reserve for deferred income taxes through June 30, 2002, should not be adopted, because it would overstate the appropriate adjustment. The Commission is not approving the inclusion in rate base of all of IP's projected capital additions through June 30, 2002. The Commission notes that the capital additions adjustment approved in this Order consists substantially of actual expenditures as of September 30, 2002.

c. General and Intangible Plant included in Distribution Rate Base

(1) IP's Position

IP states that it determined the amount of its General and Intangible ("G&I") plant investment that should be included in rate base by using labor expense allocation factors, as required by the Commission in the 1999 DST Order. (IP Ex. 1.1, pp. 5-6; IP Ex. 1.4; IP Ex. 1.34, p. 6; Tr. 749-50) IP first allocated its total G&I plant investment between the electric and gas utilities, then allocated the electric utility portion of G&I plant to electric distribution based on test year distribution labor expense divided by total test year labor expense for IP's electric transmission and electric distributions functions. (IP Ex. 1.1, pp. 5-6; IP Ex. 1.4; Tr. 750) IP states that no party noted any errors in IP's calculation of the labor allocation factors. (IP Ex. 1.34, pp. 7, 56; IP Ex. 1.63, pp. 7-8) IP states that in general, G&I plant supports all of a utility's business functions. (IP Ex. 1.34, pp. 4-5) IP notes that it is in the nature of these joint and common costs that they are needed to support a single line of business, but can also support additional lines of business without any significant increase. (Id.) IP observes that although there are some assets that the Uniform System of Accounts ("USOA") requires to be recorded in the G&I plant accounts which can be associated with specific lines of business or functions, the USOA does not require that a utility maintain its books of account or financial reports in a manner that allocates or assigns its G&I plant investment among the utility's various business functions. (IP Ex. 1.63, p. 6; Tr. 755-57) Therefore, for regulatory purposes in setting rates for one of a utility's several lines of business, it is necessary in some manner to allocate or assign a portion of the G&I plant investment to the service for which rates are being set. It is the Company's position that it has made a proper allocation of its G&I plant to distribution for purposes of this case by using labor expense allocation factors as directed by the Commission in the 1999 DST Case. (IP Init. Br., pp. 14-16)

IP's opposes Staff's and IIEC's proposed adjustments to the G&I plant in distribution rate base. IP notes that at the root of each witness' contention is the fact that in the fourth quarter of 1999, IP sold its fossil generations stations to Dynegy Midwest Generation, Inc. ("DMG") (formerly known as Illinova Power Marketing, Inc., or IPMI, and sometimes referred to as "WESCO"), and sold its nuclear generating station (Clinton) to AmerGen. IP's fossil generation employees and nuclear generation employees became employees of DMG and AmerGen, respectively. IP states that as a result, whereas during the 1997 test year used in the 1999 DST Case IP owned generating stations, had a generation business function and had generation employees whose labor expense was included in the denominator of the labor expense allocation factor, in the 2000 test year used in this case, IP owned essentially no generation, had essentially no generation labor expense, and therefore did not include any generation labor expense in the development of its labor expense allocation ratios for G&I plant. (Staff Ex. 5.0, pp. 5-6; IIEC Ex. 3, pp. 8-9; see IP Ex. 1.34, pp. 5-6) (IP Init. Br., pp. 16-17)

IP states that it properly determined the amount of its G&I plant investment that should be included in distribution rate base using a labor expense allocator as prescribed by the Commission in the 1999 DST Case. IP argues that Staff witness Lazare's and IIEC witness Phillips' proposed adjustments to G&I plant were not based on any sort of detailed review of IP's overall G&I plant assets or on identification of any G&I assets or amounts that were imprudently incurred or are unnecessary to provide service; rather, their adjustments are grounded in an erroneous premise that the Commission, in the 1999 DST Case, determined a fixed and immutable relationship between the amount of distribution plant and the amount of G&I plant needed to provide distribution service, which should be carried forward in all future cases. (IP Ex. 1.63, pp. 8-9) IP states that is no basis for such a premise, or for the arbitrary limitations that Staff and IIEC would impose on the amount of IP's G&I assets to be included in distribution rate base. (IP Init. Br., pp. 17-18)

IP states that the basis of Staff witness Lazare's objection appears to be a belief that the amount of G&I plant allocated to the generation function in the 1999 DST Case must be permanently allocated to generation, and that IP should have somehow disposed of that G&I plant when it sold its generating stations to DMG and AmerGen. IP states that Mr. Lazare believes that when IP divested its generation, it should have reduced G&I Plant and A&G expense accounts that provide the foundation for delivery services ratemaking in a manner consistent with the Commission's Order in Docket No. 99-0134. (IP Ex. 1.34, p. 16) IP disagrees with Staff witness Lazare's contentions. (IP Init. Br., p. 18)

IP witness Peggy Carter, the Company's Vice President and Controller, testified that IP transferred substantial G&I plant to DMG and AmerGen in connection with the sale of the generating stations. Ms. Carter testified that IP's October 1999 sale of its fossil generating stations to DMG was approved by the Commission in Docket 99-0209, a case initiated by a filing by IP under §16-111(g) of the Public Utilities Act ("PUA"). She stated that IP's filing contained a detailed listing of G&I plant being transferred to DMG as part of that transaction, with an original cost of approximately $12.0 million and a depreciated original cost of approximately $8.3 million. (IP Ex. 1.34, p. 11; IP Ex. 1.62) She explained that G&I plant transferred to DMG included buildings, office furniture and equipment, personal computers, computer software, vehicles, stores equipment, tools, shop and garage equipment, laboratory equipment, power-operated equipment and communications equipment. Similarly, Ms. Carter explained that the December 1999 sale of Clinton to AmerGen included G&I assets with a book value of approximately $43 million before IP recognized an impairment loss for Clinton that resulted in the entire plant value being written down to zero. (IP Ex. 1.34, pp. 12, 14) These costs included mobile and non-mobile machinery, computer hardware and software, communications equipment, vehicles, tools, spare parts, fixtures, furniture and furnishings, and other personal property. Ms. Carter testified that in total, G&I plant that had had a book value of approximately $55 million was sold to the new owners of IP's generating stations. (Id., p. 14) Ms. Carter also testified that at the time of the sales to DMG and AmerGen, there were no concerns or complaints raised by Commission Staff or anyone else that IP was not transferring enough G&I plant to the new owners of the generating facilities. (IP Ex. 1.34, p. 16) She also noted that in this case, Staff has not identified any additional G&I plant items that Staff contends should have been transferred to DMG or AmerGen. (Id., p. 17) (IP Init. Br., pp. 18-19)

Ms. Carter also testified that subsequent to the sale of its fossil and nuclear generation, IP has continued to take other actions to reduce the level of its G&I plant, by consolidating facilities and eliminating unneeded assets. She noted that IP is selling a building that had been intended for use as offices for its fossil generation management personnel, and that IP has closed and sold a facility that was once used to house historical records and moved the records to space that became available in another facility. (IP Ex. 1.34, p. 15) (IP Init. Br., p. 20)

Ms. Carter explained that other G&I plant that, had IP continued to own generating facilities, might have been allocated among generation, distribution and other functions for ratemaking purposes, was not sold or transferred to DMG or AmerGen, or otherwise disposed of, for two reasons. First, the remaining G&I assets are needed to support IP's remaining lines of business, including electric distribution. (IP Ex. 1.34, p. 14-15; IP Ex. 1.63, pp. 7, 10, 11, 13) Second, many of the G&I assets simply are not severable in a manner that would permit an "allocated portion" of them to be sold to the new owners of IP's generating stations. (Id., pp. 11, 13) She testified that when IP exited the generation business, the G&I plant that was allocated to the generation function by the labor allocator in the 1999 DST Order did not cease to exist, nor could the portion of G&I plant that had been allocated to the generation function be somehow broken apart, and sold or transferred to the new owners of IP's generating facilities, other than the specifically identifiable G&I plant which IP in fact transferred to the new owners. Ms. Carter testified that these G&I assets continue to be needed to support IP's remaining lines of business. (IP Ex. 1.63, pp. 9-10) She testified that it is the nature of joint and common costs that they are needed to support a single line of business but can also support additional lines of business without any significant increase; correspondingly, the elimination of one of several lines of business does not necessarily mean that common costs can be reduced significantly. (IP Ex. 1.34, p. 5) IP states that Staff witness Lazare accepted this proposition in cross-examination. (Tr. 776) (IP Init. Br., pp. 20-21)

IP argues that Staff witness Mr. Lazare has treated the Commission's use of the labor allocator in the 1999 DST Case as a determination that a fixed portion of IP's G&I plant assets is permanently and causally associated with IP's former generation assets. IP states that while the labor allocator is a technique used to fairly allocate a utility's G&I plant (and A&G expenses) among all its utility functions for costing and ratemaking purposes in setting rates for one of those utility functions, an allocation of G&I plant using the labor expense allocator does not establish an actual causal relationship between the activities of each line of business and the amount of G&I plant (and A&G expenses) required to support it. IP states that the allocation of common costs among business functions using the labor expense allocator does not establish the amount of G&I plant (or A&G expenses) that would be needed to operate a business function on a stand-alone basis. (IP Init. Br., pp. 21-22)

IP responded to Staff witness Lazare's assertion that the fact that IP divested its generation assets and generation business "did not change the way that the generation utility causes common costs to be incurred." (Staff Ex. 5.0, p. 12) IP states that Mr. Lazare's assertions ignore the fact that, during the 2000 test year, IP was no longer a "generation utility," nor did it own the entities which acquired its generation assets and business. IP also states that although it was indicated in Docket 99-0209 (the case in which the sale of IP's fossil generation to DMG was approved) that DMG might for a period of time continue to obtain certain administrative, overhead and support services from IP, it was also indicated in that case that "[i]n the future, [DMG] may develop internal capabilities to provide some or all of these services, or may elect to obtain services from competitive third party providers." (IP Cross Ex. 2, p. 14; see Staff Ex. 5.0, pp. 12-13) IP witness Carter testified that IP did supply such services to DMG for a brief period after the transfer, but that after the Illinova-Dynegy merger was closed in February 2000, many of the administrative and overhead functions that IP was performing for DMG were taken over by Dynegy, including such services as human resources, financial planning and management, cash management and treasury, insurance and claims, internal auditing, public affairs, some legal services and some procurement services. As a result, many of DMG's administrative support functions are now provided directly by Dynegy. (IP Ex. 1.34, pp. 60-61) (IP Init. Br., pp. 22-23)

Ms. Carter detailed the services that IP provided to DMG and to AmerGen during the 2000 test year. She testified that IP provided services totaling $11,160,347 to AmerGen in 2000 and provided services totaling $9,533,574 to DMG in 2000. (IP Ex. 1.34, pp. 57, 59; IP Exs. 1.56-1.57) Ms. Carter explained that those services still being provided by IP to DMG are priced using fully distributed costs as required in the Services and Facilities Agreement ("SFA") among IP, Dynegy and the other Dynegy subsidiaries that was approved by the Commission in Docket 99-0114. (IP Ex. 1.34, p. 61) She explained the accounting treatment used by IP for revenues received for services provided by IP to AmerGen and to Dynegy and the related costs, and testified that neither the revenues nor the costs were included in setting the distribution revenue requirement in this proceeding. (Id., pp. 57-60; IP Ex. 1.63, pp. 36-37) IP points out that neither Staff witness Lazare nor IIEC witness Phillips presented any evidence that IP provided A&G services or G&I facilities to AmerGen or DMG in 2000 for which IP was not properly compensated. (See Tr. 707, 770-73) (IP Init. Br., p. 23)

IP also responded to Staff witness Lazare's contention that IP was precluded from increasing the amount of its G&I plant allocated to electric distribution because, in Docket 99-0209 (the case in which the transfer of IP's fossil generation to DMG was approved), IP made a "commitment" that delivery services rates would not be increased as a result of the transfer. (Staff Ex. 14.0, p. 5; see also Staff Ex. 5.0, pp. 9-11) IP noted that Mr. Lazare based this contention on the testimony of IP witness Alec Dreyer in Docket 99-0209 that "Illinois Power's electric customers will see no difference in the level or quality of service they receive, nor will the price they pay increase as a result of the transfer to [DMG]." (Staff Ex. 5.0, p. 10) IP argued that Mr. Lazare's references to the testimony in Docket 99-0209 do not support his position. IP notes that IP's §16-111(g) filing to transfer its fossil generating stations to DMG was made on April 16, 1999; that the testimony from that case cited by Mr. Lazare was filed shortly thereafter; and that the Commission issued its order approving the transfer (including the transfer of the G&I assets listed in the filing) on July 8, 1999. (IP Ex 1.34, pp. 9-10; Tr. 762) IP points out that although IP had filed its initial DST case in March 1999, the Commission's order in that case was not issued until August 25, 1999, and the initial provision of delivery services did not commence until October 1, 1999. IP states that at the time the Docket 99-0209 testimony cited by Staff witness Lazare was filed, there were no customers taking delivery services or paying delivery services rates; in fact, the Commission had not yet issued its order in the 1999 DST Case adopting the labor expense allocation approach for determining the amount of G&I plant to be included in distribution rate base, and setting the initial DST rates. IP further states that Mr. Dreyer's statements in Docket 99-0209 were made in the context of attempting to satisfy the two criteria that the Commission has authority to apply in reviewing a §16-111(g) transfer, namely (1) whether the proposed transaction will render the electric utility unable to provide its tariffed services in a safe and reliable manner, and (2) whether there is a strong likelihood that consummation of the proposed transaction will result in the electric utility being entitled to increase its base rates during the mandatory transition period pursuant to §16-111(d). (IP Ex. 1.63, pp. 11-12) IP states that neither of these topics would implicate the level of future delivery services rates. (IP Ex. 1.63, pp. 11-12) IP concludes that it is clear from reading Mr. Dreyer's entire testimony (IP Cross Ex. 2), including his summary at the end of his testimony, that his testimony was addressed to these two statutory criteria, and in particular, to the potential impact of the transfer on base rates during the mandatory transition period, not to the level of future DST rates. (IP Init. Br., pp. 23-25)

IP also pointed out that while Staff witness Lazare premised his argument on Mr. Dreyer's testimony in connection with the transfer of IP's fossil generation to DMG, he identified no similar statements from the case in which IP sold its nuclear generating station to AmerGen. IP notes that of the $76,240,000 of generation labor expense used in the calculation of labor allocation factors in the 1999 DST Case, $50,539,000 was nuclear generation labor expense. Therefore, approximately 66% of the G&I plant allocated to "generation" in the 1999 DST Case was allocated to nuclear generation; only about 34% was allocated to the fossil generation that was transferred to IP's affiliate, DMG. (IP Ex. 1.63, p. 12) (IP Init. Br., pp. 25-26)

IP also responded to Staff witness Lazare's contention that IP's allocation of G&I plant (and A&G expense) in this case was inconsistent with Ameren's treatment of G&I plant and A&G expense in its DST case that was filed in December 2000, Docket 00-0802. (Staff Ex. 5.0, pp. 8-9; Staff Ex. 14.0, p. 4) IP stated that in Docket 00-0802, Ameren allocated a portion of its G&I plant (and A&G expense) to "generation", but that the test year in that case was a 12-month period ending in 1999, during which the Ameren companies owned and operated generating facilities. IP notes that although AmerenCIPS has transferred generating facilities and the generating business to an affiliate, this transfer did not occur until after the period being used as the test year in Docket 00-0802. IP concludes that under the circumstances of Docket 00-0802, including the test year chosen by the utilities in that case, it was appropriate for Ameren to allocate a portion of G&I plant to the generation business. IP states that the facts are different in this docket, because IP had exited the generation business prior to the test year used in this case, and during the test year used in this case owned essentially no generation and had essentially no generation–related labor expense. (IP Ex.1.34, pp. 8-9; IP 1.63, pp. 14-15; Tr. 760-61) (IP Init. Br., pp. 26-27)

In response to Staff's and IIEC's assertions that IP's allocation of G&I plant and A&G expense in this case raised the issues of "least cost ratemaking", IP states that Staff cited no statute, regulation or Commission order that defines or establishes "least cost ratemaking." IP acknowledged that Ms. Carter did testify that IP has an obligation to provide service to delivery services customers at least cost, but IP states that the issue in this case has nothing to do with provision of service at least cost. Instead, IP states, the issue is how to spread common costs that are already on the utility's books among its various lines of business for ratemaking purposes. IP contends that it has shown that it is providing delivery services on a least-cost basis by disposing of plant it no longer needs and taking other actions to reduce operating costs. IP states that Staff provided no rebuttal to IP's evidence on this point, and identified no items of G&I plant or A&G expense that Staff contended were imprudent, excessive or not "least cost." (IP Rep. Br., pp. 10-11)

It is IP's position that its overall G&I plant balances are reasonable. IP witness Carter presented IP Exhibit 1.39 which detailed the changes in IP's G&I plant accounts on a year-by-year basis from December 31, 1997 (the end of the test year used in the 1999 DST case) to December 31, 2000 (the end of the test year in this case). IP Exhibit 1.39 showed that overall, the original cost of plant in service recorded in Accounts 301-303 and 389-399 increased from $371.1 million at December 31, 1997 to $385.0 million at December 31, 2000, an increase of about $14 million (3.7%). (IP Ex. 1.34, p. 17) Ms. Carter testified that although IP transferred approximately $55 million of G&I plant to DMG and AmerGen in 1999, IP has continued to make necessary and reasonable investments in G&I plant from December 31, 1997 through December 31, 2000. (Id.) IP notes that in this case, it explained and justified its individual additions to G&I plant costing in excess of $250,000 that were placed in service between December 31, 1997 and December 31, 2000. (Corrected IP Exs. 1.32-1.33; Corrected Rev. IP Exs. 2.4-2.5) IP also described the additions to G&I plant to be placed in service between January 1, 2001 and June 30, 2002, that IP is proposing to include in rate base in this case. (Corrected Rev. IP Ex. 1.5, IP Ex. 1.64, Corrected Rev. IP Exs. 2.8-2.9, IP Exs. 2.15 and 2.19-2.20) IP points out that no witness contended that any of these G&I capital additions projects (either the ones placed in service in 1998-2000, or the ones being placed in service in 2001-2002) were imprudent, excessive or unnecessary. IP also notes that in the 1999 DST Case, it presented evidence to describe and justify significant G&I plant additions that had been made or were planned subsequent to 1992, when an electric rate base was last established for IP, through 2000. (IP Ex. 1.34, p. 7) IP concludes that through its evidence in the 1999 DST Case and in this case, IP has justified its major G&I plant additions from at least 1992 through 2001-2002. (IP Ex. 1.63, pp. 17-18) IP reiterates that neither Staff witness Lazare nor IIEC witness Phillips identified any specific items of G&I plant that they contended were imprudent, unnecessary to support the distribution business or that otherwise should not be included in rate base. (IP Ex. 1.34, pp. 17, 20; IP Ex. 1.63, pp. 15-16; Tr. 778-780) (IP Init. Br., pp. 27-28)

IP argues that IIEC's comments on IP Exhibit 1.72 are misplaced. IP states that IP Exhibit 1.72 shows that IP's ongoing level of electric A&G expense has decreased by $37.2 million (53.2%) from 1997 to 2000, to $34.2 million. IP contends that IIEC's assertion that IP has not in fact removed the non-recurring 2000 expenses listed in IP Exhibit 1.72 for ratemaking purposes, and that IP is requesting $41.8 million of A&G expense in the distribution revenue requirement, not $34.2 million, miss the mark. IP states that three of the six non-recurring items listed on IP Exhibit 1.72 have been completely removed from the distribution revenue requirement in this case (salaries and benefits associated with transition employees, correction of SFA allocation methodology and Duke Engineering litigation expense. IP further states that two of the remaining three items (severance costs accrued in 2000 and the $5.5 million accrual for injuries and damages) have been removed from the test year expenses but are being amortized over multi-year periods, so the annual amortization is reflected in the distribution revenue requirement. IP states that only the item for incentive compensation accrued expense remains in the distribution revenue requirement. Second, IP states that IP Exhibit 1.72 does not reflect post-test year adjustments to operating expense, such as adjustments for the load research project, rate case expense, postal rate increase, increased insurance costs, wage and salary increases in 2001, and increased FICA expense in 2001, as well as other one-time ratemaking adjustments such as for the operations compliance program startup costs and storm damage expense normalization, none of which have been contested by IIEC (or any other party). IP states that because it does not take these and the other pro forma adjustments into account, IIEC's attempt to revise the numbers on IP Exhibit 1.72 to try to justify its proposed A&G expense adjustment is incomplete and meaningless. IP reiterates that overall, IP Exhibit 1.72 shows that Illinois Power achieved a substantial reduction in electric A&G expenses from 1997 to 2000. (IP Rep. Br., pp. 19-21)

IP also argues that the methods proposed by IIEC and Staff for determining the amount of G&I plant and A&G expense to be included on the distribution revenue requirement would constitute bad policy. IP states that Staff and IIEC's methods would penalize a utility for making investments in G&I plant (such as computer equipment and software, telecommunications equipment, and other information technology assets) in order to reduce direct distribution expenses (such as O&M or customer accounts labor expense), and would thus discourage such cost-effective investments. Similarly, IP contends that Staff's and IIEC's approach would discourage utilities from taking other actions to reduce direct distribution O&M expense, since such efforts would carry a penalty of the disallowance of a commensurate amount of G&I plant and A&G expense from the revenue requirement. IP states that Staff's and IIEC's approaches would discourage, rather than encourage, the provision of delivery services on an economical, efficient and least-cost basis. (IP Rep. Br., p. 21)

In summary, it is IP's position that it properly determined the amount of G&I plant that should be included in distribution rate base using the labor allocation expense approach adopted by the Commission in the 1999 DST Case; that no party identified any errors in IP's calculation of the labor expense allocation factors; that IP justified the overall level of its G&I plant accounts; that it transferred $55 million of G&I plant to the parties that acquired its generating stations, and has taken other actions to reduce its level of G&I plant where possible; and that no party identified any items of G&I plant that IP proposes for inclusion in rate base that are imprudent, unreasonable or unnecessary. IP contends that Staff's and IIEC's proposed limitations on the amount of G&I plant in rate base display a fundamental misunderstanding of the nature of common costs, and that these parties have not refuted IP's showing that its remaining G&I assets are needed to support its existing businesses of gas, electric transmission and electric distribution, and have not identified any G&I plant items included in distribution rate base that are not needed to support the distribution business. (IP Init. Br., pp. 28-29)

(2) Staff's Position

Staff contends that IP's proposed labor allocator for allocating G&I plant to distribution falls short of what the Commission ordered in the 1999 DST Case because it purposefully excludes the generation function. Staff contends that IP has reassigned costs that the Commission previously allocated to generation to transmission and distribution ("T&D") and then allocated between these functions using a truncated labor allocator. Staff contends that this results in a significant reallocation of G&I plant and A&G accounts from generation to distribution and a sizeable increase in delivery service rates. Staff argues that in the 1999 DST Case, the Commission established a clear precedent on these issues by accepting the labor allocator approach for General plant and for A&G expense. (1999 DST Order, pp. 16 and 30) (Staff Init. Br., pp. 5-6)

Staff stated that IP has not contested the use of the labor allocator and has acknowledged its legitimacy for functionalization in this proceeding. Staff states, however, that IP's proposal includes extraordinary increases for G&I plant and A&G accounts, which demonstrate that IP has fundamentally diverged from the Commission Order in Docket No. 99-0134. Staff notes that IP's proposed allocation of $257,381,000 of G&I plant to distribution represents a $183,478,000 (or 248%) increase over the $73,903,000 allocation approved by the Commission in the 1999 DST Case, and represents an increase of $88,244,000 (or 52%) over IP's own proposal in the 1999 DST Case. (Staff Ex. 14.0, p. 11) Staff notes that since the last delivery services case, IP divested all of its generation, but still incurred a $14 million increase in its overall G & I plant balances. Staff also notes that IP's proposed $47.14 million in A&G expenses represents an increase of $31.22 million (or 196%) over the $15.92 million approved by the Commission in the 1999 DST Case. (Staff Ex. 14.0, p. 14) Further, IP's proposed distribution A&G expenses represent an increase of $11.94 million (or 34%) over the $35.20 million IP proposed in the 1999 DST Case. (Staff Ex. 14.0, p. 15) The Commission notes that IP's final proposed A&G amount for purposes of this case is $41.7 million. (Staff Init. Br., pp. 8-9)

Staff contends that IP's labor allocator is fundamentally flawed. According to Staff, IP has adhered to the 1999 DST Order concerning a labor allocator in name only, because the labor allocator used in that case included the generation function but IP's proposal here does not. (Staff Ex. 5.0, p. 7) Staff states that IP's omission alters the allocations fundamentally and significantly increases the allocation of G&I plant and A&G accounts to delivery service. (Staff Ex. 14.0, p. 3) Staff states that in the wake of its divestiture of its generation plants, IP adopted an allocation methodology which effectively undermined the labor allocator from the 1999 DST Case, which allocated a majority of G&I plant and A&G accounts to generation. Staff states that IP's new methodology leaves delivery services with a far greater allocation of these accounts than before. (Staff Ex. 14.0, p. 6) Staff contends that IP used T&D as a dumping ground for costs that the Commission had expressly allocated to the generation function. (Staff Init. Br., pp. 9-10)

Staff notes that IP witness Carter indicates that IP sold or transferred to the purchasers of IP's generation facilities about $54 million in G&I plant (IP Ex. 1.34, p. 14), considerably less than the $87.6 million IP proposed to allocate to generation in the 1999 DST Case. (Staff Ex. 14.0, p. 6) Staff states that IP proposes to saddle the regulated T&D utility with an additional $33.6 million in G&I plant that it had identified as generation-related in Docket No. 99-0134. (Staff Ex. 14.0, p. 7) Staff states that IP witness Carter admitted that IP has reallocated costs from generation to distribution and that she confirmed this would result in an increase in the distribution revenue requirement. (Citing Tr. 169 and 171-72 and IP Ex. 1.34, p. 63). (Staff Init. Br., pp. 10-12)

Staff contends that by reallocating costs to distribution, IP is asking ratepayers to pay a penalty for its own decision to divest generation. (Staff Ex. 14.0, pp. 17-18) Staff notes that IP witness Carter admitted that divestiture was strictly a business decision made by IP without any pressure from the Commission. (Tr. 155) Staff contends that there is no justification for asking that delivery service ratepayers pay more to reflect the changing relationships that result from the decision to divest. Staff also argues that the fact that IP may be asking delivery service ratepayers to pay more because of the divestiture raises the issue of least cost ratemaking because IP's divestiture strategy places upward pressure on the delivery service revenue requirement. Staff states that if IP's functionalization proposal is accepted, the resulting rates could come into direct conflict with the objective of least cost ratemaking. (Staff Init. Br., p. 13)

Staff also contends that the significant increases IP proposes for common costs runs counter to savings claims made for the Dynegy merger. Staff notes that in announcing the merger, Dynegy had identified projected revenue enhancements and savings for the merger ranging from $125 to $165 million, with approximately two-thirds of the total annual synergies attributable to revenue enhancement opportunities while the remaining one-third of the total annual synergies were attributable to cost savings. (Staff Ex. 5.0, pp. 13-14) Staff notes that in Docket No. 99-0419, in which the Commission reviewed the gas utility component of the merger, IP indicated that more than $30 million in savings were expected from corporate and operations support staffing and more than $20 million from corporate and administrative programs. The reductions in corporate and administrative programs were indicated to include A&G expenses that are variable with the number of employees, the elimination of duplicative advertising programs, and the elimination of duplicative professional services, insurance and information services costs. Staff also noted that Dynegy's statement that a significant portion of these savings should be realized in the first year of operation suggests that the cost reductions will show up sooner rather than later. (Staff Ex. 5.0, pp. 14-15) Staff contends that these forecasted savings have failed to materialize for IP delivery service customers who, instead, are facing disproportionate increases in common costs. Staff argues that this indicates that IP has no interest in sharing savings from the Dynegy merger with delivery service ratepayers. (Staff Init. Br., pp. 13-14)

Staff contends that IP's proposed increase in common costs calls into question assurances by IP that its divestiture of generation plant would not adversely impact rates or competition in the electricity market. Staff notes that in Docket 99-0209, which concerned the divestiture of IP's fossil plants, IP witness Dreyer assured the Commission that no electric customers would be adversely affected by the divestiture, including in the price they pay for services. Staff contends that IP's proposals to increase common costs directly conflict with these assurances. Staff states that IP has shifted a considerable sum of common costs to the regulated utility in the course of divestiture, which not only saddles delivery services customers with potentially higher rates in the current proceeding, but lays the foundation for higher rates for all electric customers when their bundled rates are updated. In addition, Staff argues that whereas IP had indicated that divestiture would be a boon to competition, IP's proposal in this case undermines this assurance as well. Staff states that by shifting a considerable sum of common costs to the regulated utility, IP has laid the groundwork for delivery services rates to rise relative to bundled rates, thereby making delivery services a less attractive alternative to bundled service for IP customers and undermining the competitiveness of the electricity market, as well as making IP's affiliates more competitive at the expense of others. (Staff Ex. 5.0, p. 11) In addition, Staff rejects IP witness Carter's position that in Docket 99-0209, Mr. Dreyer's statements were intended to apply to bundled service customers and rates only. Staff contends that the Commission should hold IP to its promises in this proceeding. (Staff Ex. 14.0, pp. 5-6) (Staff Init. Br., pp. 14-17)

Staff also contends that IP has attempted to criticize the labor allocator in this case and argued that only a study such as the asset separation study IP presented in the 1999 DST Case can appropriately assign common costs to functions. Staff argues that IP's discussion of this point is too little, too late because in the 1999 DST Case, the Commission explicitly rejected IP's study in favor of a labor allocator. (IP Ex. 1.34, p. 6) (Staff Init. Br., p. 17)

Staff also argues that IP's proposed labor allocator falls short of the allocator proposed by Ameren in its current delivery service case. (Docket No. 00-0802) Staff states that IP's proposal falls short of Ameren's proposal for a labor allocator that includes not only T&D, but generation as well. Staff contends that if the Commission accedes to IP's proposal in this case, it will be applying a double standard that favors those utilities that disregard Commission Orders over utilities that adhere to those Orders. (Staff Ex. 5.0, p. 9) Staff states that while Ameren includes the generation function in the allocation of common costs, IP has adopted a contrary approach that reallocates a sizeable share of these costs from generation to transmission and distribution costs. (Staff Init. Br., pp. 17-18)

Staff disagrees with IP witness Carter's testimony that in the event the Commission rejects IP's proposed allocation methodology, it should at a minimum approve IP's proposed additions to G&I plant since January 1, 2000, since according to Ms. Carter these capital additions are clearly distribution-related and, therefore, should be included in the distribution rate base in their entirety. Staff contends that IP has failed to present a compelling case for considering these additions to be distribution-related in their entirety, in that the evidence cited by Ms. Carter (IP Exs. 1.32, 1.33, 2.4 and 2.5) fails to demonstrate that these additions solely relate to the distribution function and could not serve other functions as well. (Staff Init. Br., p. 18)

Staff contends that its proposal for G&I Plant and A&G accounts maintains consistency with the spirit and intent of the 1999 DST Order while conforming to the structural and ownership changes IP has undertaken since the previous case. Staff proposes that changes in G&I plant and A&G account levels should be proportional to changes to the associated direct accounts. That is, the increase in G&I plant should be commensurate with the increase in other distribution plant accounts, and any change in A&G expenses should be consistent with the changes in direct O&M expenses. Staff states that its proposal would make rates consistent with IP's statement that electric ratepayers should not be adversely affected by IP's divestiture of generation, in contrast to IP's proposal, which would require delivery services customers to foot the bill for divestiture. Staff states that in addition, its proposal would produce consistent results with the 1999 DST Case. (Staff Ex. 5.0, pp. 15-17) (Staff Init. Br., pp. 18-19)

Based on its methodology, Staff proposes that the increase in the G&I accounts be limited to the same 20.91% percentage increase IP proposes for distribution plant. This produces a proposed increase in G&I plant from IP's proposed level of $109,978,000 to $132,972,000 and a downward adjustment of $142,557,000 in G&I plant from IP's proposed level of $275,529,000. Parallel analyses produce an increase of $3,911,000 in G&I depreciation reserve and a decrease of $8,763,000 in General Plant depreciation and Intangible Plant amortization expense. (Staff Ex. 5.0, pp. 17-18) (Staff Init. Br., pp. 19-20)

With respect to A&G expense, Staff states that the starting point for its A&G adjustment is the distribution O&M expenses that Staff finds have increased by 4.16%, from $67,125,000 in Docket No. 99-0134 to $69,920,000 in this case. Staff proposes that the $23,860,000 in A&G expense the Commission allocated to distribution in the 1999 DST Case (before ratemaking adjustments) be increased by 4.16% to $24,854,000. This proposal produces a $22,287,000 downward adjustment in the $47,141,000 in A&G expenses proposed by IP. (Staff Ex. 21.0, p. 1) The Commission notes that the numbers produced by Staff's approach differ from the foregoing when IP's final proposed A&G expense amount of $41.7 million is used. (Staff Init. Br., p. 20)

Staff notes that in addition to the adjustments just described, Accounting Staff made other adjustments to G&I plant, Reserve and Depreciation and Amortization and A&G expense accounts. Staff states that these functionalization adjustments represent Staff's preferred position in this case, and that if they are approved, the other Staff adjustments in these areas are no longer relevant. Staff notes that if the Commission decides against the proposed functionalization adjustments, then it should give consideration to the other Staff adjustments in this area. (Staff Init. Br., pp. 20-21)

Staff contends that IP's criticisms of Staff's approach are deficient in a number of respects, in that some of them were already presented but not accepted in the 1999 DST Case, and that in any event IP's arguments do not provide a compelling argument for rejecting the Staff approach in favor of IP's approach. (Staff Ex. 14.0, pp. 9-10) Staff also notes that IP's fossil plants were transferred to a subsidiary of IP and that according to IP witness Carter, it is possible for IP to allocate costs associated with those buildings (and other common plant for that matter) to the current owner of those generation units, DMG (citing Tr. 180). (Staff Init. Br., pp. 21-22)

(3) IIEC's Position

IIEC proposes a level of net G&I plant for distribution rate base of $111,110,000. IIEC's proposal is a reduction in net G&I plant of $69.9 million from IP's revised request, and is a $35.9 million increase over the level of G&I plant allowed in the 1999 DST Order. (IIEC Ex. 3, Sch.2) Based on the level of net G&I plant, IIEC recommends a level of depreciation and amortization expense for G&I plant of $7.2 million as shown on IIEC Exhibit 3, Sch 2. This is a reduction of $5.0 million from IP's revised request. With respect to A&G expense, IIEC recommends $16.8 million of A&G expenses for distribution service, which is a reduction of $25.0 million from IP's request. (IIEC Ex. 3, Sch. 1) It is IIEC's opinion that IP should not be allowed to increase the amount of A&G expense associated with distribution service, nor should IP be allowed to increase the net amount of G&I Plant costs associated with distribution service, as it proposes. IIEC contends that the better approach is to allow A&G expense to increase in proportion to the authorized increase in other (non-A&G) O&M expense in this case. IIEC recommends the same approach with regard to net G&I Plant costs, that is, these costs be increased in proportion to the authorized increase in other (non-A&G) O&M expense. (IIEC Init. Br., pp. 5-6)

IIEC states that IP's requested increases in A&G expenses and net G&I Plant costs drive the increase in the revenue requirement in this proceeding. IIEC calculates that the requested increases in A&G expenses and G&I Plant costs account for about 60% of the revenue requirement sought by IP. (IIEC Ex. 3, p. 3) IIEC notes that the A&G expense allowed in the 1999 DST Case was $15.9 million whereas here IP is requesting $41.8 million, and that in the 1999 DST Case the Commission approved $75.2 million in net G&I Plant costs; in this proceeding, IP initially requests $181 million. (IIEC Ex. 3, Schs. 1 & 2, IP Ex. 3.15, p. 3) Further, depreciation expense for G&I Plant is proposed to be increased from $2.9 million in the 1999 DST Case to $12.2 million. (IIEC Ex. 3, pp. 4-5 and Sch. 2; IP Ex. 3.15, p. 3) IIEC also notes that in the 1999 DST Case the Commission allowed O&M expense of $67 million for delivery services; therefore, for each dollar of O&M expense authorized by the Commission, approximately 23.7¢ of A&G or "overhead" was found as a reasonable cost to provide delivery services. (IIEC Ex. 3, p. 5) IIEC states that under IP's request in this case, there is A&G expense of about 60 cents per dollar of O&M expense. (IIEC Ex. 3, p. 6) (IIEC Init. Br., pp. 7-8)

IIEC contends that IP has failed to explain the basis for the significant increase in these expenses and that its reliance upon the so-called "labor allocator" is suspect. IIEC states that a significant amount of A&G expense was allocated to the production function in the 1999 DST Case, but in this proceeding IP does not allocate any A&G to the production function because its generating assets have either been sold or transferred. IIEC states that because IP has sold or transferred its generating assets does not in itself mean that A&G expenses required for distribution services should triple. (IIEC Ex. 3, p. 7) IIEC also believes that IP should not be allowed to reflect the full amount of its requested G&I Plant cost in its revenue requirement, because in the 1999 DST Case the Commission found that more than half of IP's requested G&I Plant costs were not related to distribution. (IIEC Ex. 3, p. 10) (IIEC Init. Br., p. 8)

It is IIEC's position that the determination of A&G in this case should reflect the level of O&M expense in relation to the amount of overhead or A&G expense to be recovered in rates in this proceeding, based on the 1999 DST case. IIEC's approach takes the 23.7% overhead requirement from the 1999 DST case and uses that percentage as a ratio to A&G expense to be recovered, which produces a result of $16.8 million. (IIEC Ex. 3, p. 8) With respect to G&I plant, IIEC's position is that the initial amount of net G&I plant be increased in proportion to the increased amount of O&M expense required for delivery service. Net G&I Plant costs would be increased by the same percentage amount that IP's requested O&M expense level increased over the previously authorized amount. This results in a decrease of 69.9 million from IP's request of $180.9 million for net G&I Plant, to a more reasonable $111.1 million cost level. Depreciation expense associated with G&I Plant would be similarly adjusted. (IIEC Ex. 3, pp. 9-10) IIEC notes that its recommended amount of net G&I Plant of $111.1 million is 11.8% of the rate base proposed by IP in this proceeding as compared to 11.4% in the 1999 DST Case and 19.4% under IP's proposal. (IIEC Ex. 3, p.10 and Sch. 2) (IIEC Init. Br., pp. 8-9)

IIEC states that IP did not provide any studies substantiating whether IP pursued the most cost efficient and economic level of A&G expense for the provision of distribution service for IP, and that in the context of this case, there were no studies done by IP, economic or otherwise, regarding the most cost efficient and economic level of A&G expense for the provision of delivery services to IP customers. IIEC argues that IP has not met its burden of justifying the increased level of A&G, what it represents, why it is required or what amount of A&G is economic or efficient for the provision of delivery services. IIEC contends that in developing a delivery services revenue requirement, it is not sufficient to simply argue, as IP does, that there are "fewer lines of business" over which to allocate the A&G expense remaining after divestiture of IP's generation. (IP Ex. 1.34, p. 56) IIEC also states that IP did not produce any studies that evidenced a determination of the most economic and efficient levels of G&I plant required to provide distribution services. (IIEC Ex. 6, pp. 2-4) (IIEC Init. Br., pp. 9-10)

IIEC states that IP's rebuttal concerning its A&G expense levels was not persuasive. IIEC states that while Account 923, Outside Services Employed, had increased by $25.2 million, primarily attributable to the billings to IP associated with services now provided by Dynegy, Inc., IP did not produce any studies or analysis showing the economic advantage or cost savings associated with obtaining services from Dynegy, Inc. (IIEC Ex. 6, pp. 4-5) IIEC argues that IP should not become a conduit for the collection of unexplained Dynegy overheads through the imposition of significant amounts of increased A&G in IP's delivery service rates. IIEC also states that while IP presented IP Exhibit 1.72 to show that if "Significant Unusual and Non-

Recurring Expenses Removed for Ratemaking Purposes" are subtracted from the year 2000 A&G amount, the total company A&G expense level before functionalization would be approximately $34.4 million, IP did not remove these amounts for ratemaking purposes; moreover, IP is actually requesting $41.8 million of A&G in rates; and the total on IP Exhibit 1.72 for 2000 includes A&G for transmission service and bonuses for Dynegy executives. IIEC states that after subtraction of A&G expense for transmission service and for Dynegy, Inc. bonuses, the remainder would be very close to the amount of A&G found appropriate for delivery service in the 1999 DST Case. In conclusion, IIEC states that IP has not met its burden to justify the level of A&G expense and G&I plant required for the least cost provision of delivery services. (IIEC Init. Br., pp. 10-11)

(4) Commission's Analysis and Conclusion

The Commission concludes that the procedure employed by Illinois Power to determine the amount of its G&I plant investment that should be included in distribution rate base is appropriate and consistent with the procedure that the Commission determined should be used in the 1999 DST Case, i.e., based on the ratio of distribution labor expense for the test year to IP's total direct electric expense for the test year, 2000. The Commission notes that no party raised any issues with respect to IP's allocation of G&I plant between the electric and gas utilities or with respect to IP's calculation of the distribution labor expense ratios. The Commission concludes that the amount of G&I plant that should be included in distribution rate base for purposes of this case is the amount proposed by IP, as adjusted based on any specific adjustments to G&I plant that are adopted by the Commission in other sections of this Order.

The Commission does not accept Staff's contention that based on the 1999 DST Order, IP should be required to allocate a portion of its G&I plant to "generation" even though prior to the test year in this case IP divested all of its generation, and had essentially no generation facilities, business or labor expense during the 2000 test year. The Commission also does not accept the arguments of Staff and IIEC that based on the 1999 DST Order, the mathematical relationships between G&I plant investment in distribution rate base and distribution plant, or distribution labor expense, must be maintained in this case. The Commission recognizes that it is in the nature of common costs such as G&I plant that support multiple lines of business, that the fact that one line of business and its direct assets is divested, does not mean that the amount of G&I plant can be reduced correspondingly. IP has sold its generation assets and exited the generation business, as permitted by the PUA, with this Commission's approval, and therefore IP cannot be required to continue to allocate a portion of its G&I plant investment to "generation" for purposes of setting its distribution rates. The G&I plant that IP retains subsequent to divestiture of its generation business always supported the distribution business, but it was formerly allocated among all of the lines of business for regulatory ratemaking purposes. The Commission also does not accept the arguments to the contrary made by Staff based on testimony from Docket 99-0209, the comparison to the current Ameren delivery services case, the estimates of cost savings from the Illinova-Dynegy merger, or so-called "least-cost ratemaking."

It is, of course, an appropriate inquiry as to whether, to the extent that IP is providing services and facilities to the new owners of its generating facilities, IP is being properly compensated for those services and facilities. In this case, IP detailed its billings to DMG and

AmerGen in the test year for services and facilities it provided to those companies, and showed that it was compensated based on fully-distributed costs, and that both the revenues received and the costs of the services were accounted for in such a manner that they do not affect the distribution revenue requirement in this proceeding. No party took issue with this showing.

The Commission notes that Staff and IIEC raised a legitimate issue when they called into question the increase in G&I plant that IP is proposing for inclusion in distribution rate base in this case as compared to the amount of G&I plant allowed in the 1999 DST Case. However, IP demonstrated in response that it in fact transferred a significant amount of G&I plant to the buyers of its generating stations; that it has engaged in other efforts to reduce the level of its G&I plant and to dispose of unneeded G&I plant; and that the change in its total G&I plant since 1997, the test year used in the 1999 DST Case, has been reasonable. In response to IP's evidence, no other party attempted to show that any items of IP's G&I plant in service are excessive, imprudent or unnecessary to support its distribution business (except as reflected in other specific adjustments that are discussed in other sections of this Order). For these reasons, the Commission accepts IP's proposed amount of G&I plant as appropriate for inclusion in distribution rate base in this case (again, as adjusted based on other, specific adjustments as discussed elsewhere in this Order).

d. Capitalization of severance costs

(1) IP's Position

During the test year IP incurred costs for severance and early retirement programs that resulted in elimination of 297 employees. The costs were charged to A&G accounts 920 (Administrative & General Salaries) and 926 (Employee Pensions and Benefits) under the USOA. Prior to these employees being terminated or accepting early retirement, the compensation of many of them had also been recorded to Account 920. IP states that in accordance with the standard accounting practice, IP capitalized a portion of these administrative costs. Since the severance costs were incurred to eliminate positions that were no longer required, IP concluded it was appropriate to account for these costs in the same manner as the cost that was eliminated, i.e., the compensation of the terminated employees. Accordingly, IP capitalized a portion of these A&G costs and recorded the remainder as expenses, consistent with its usual practice with respect to costs charged to Accounts 920 and 926. (IP Ex. 1.34, pp. 25-26; IP Ex. 1.63, pp. 23-24) (IP Init. Br., p. 29)

IP disagreed with Staff witness Hathhorn's position position that no part of the severance and early retirement costs should have been capitalized, and in particular with her position that severance and early retirement costs are not labor costs incurred by the utility in connection with construction and are not related to construction. IP states that the severance payments were clearly labor costs and constituted taxable wages to the employees. IP states that a careful review of the nature of these costs and the relevant provisions of the USOA shows that IP's capitalization of a portion of the costs was proper. (IP Init. Br., pp. 29-30)

IP notes that Staff witness Hathhorn relied on subsection (A)(2) of Electric Plant Instruction No. 3 of the USOA, which states that the cost of construction properly includible in the electric plant accounts shall include (among other things), "Labor." IP states that Electric

Plant Instruction No. 3(A)(2) only refers to the pay and expenses of the employees who are directly engaged in performing the construction work, i.e., the construction labor, and therefore is not really relevant to the treatment of A&G costs. IP states that Electric Plant Instruction No. 3, subsection (12) also includes in construction costs the pay and expenses of general officers and general and administrative expenses applicable to construction work, and that in addition, Electric Plant Instruction No. 4 provides for the recording of "overhead construction costs," including "general office salaries and expenses" and "relief and pensions." (Rev. Staff Ex. 10.0, p. 12; Tr. 310-11) IP points out that "general office salaries and expenses" and "relief and pensions," as referred to in Electric Plant Instruction No. 4, are the costs which, if they were being expensed, would be recorded in Account 920, Administrative and General Salaries, and Account 926, Employee Pensions and Benefits, respectively. (Tr. 310-11) (IP Init. Br., pp. 30-31)

IP states that Electric Plant Instruction No. 4 of the USOA requires that "overhead construction costs" shall either be "charged to particular jobs or units on the basis of the amounts of such overheads reasonably applicable thereto," or, where a direct charge procedure is impractical, "special studies shall be made periodically of the time of supervisory employees devoted to construction activities to the end that only such overhead costs as have a definite relation to construction shall be capitalized" and IP complied with this Instruction. Specifically, IP annually determines the percentage of costs recorded in Account 920 to be capitalized based on a study of the level of support provided to other business functions; based upon the study, a percentage of A&G to be capitalized is determined and applied to applicable costs. IP states that it used this percentage to determine the amount of severance costs to be capitalized, consistent with its treatment of all other A&G costs. IP also used the same percentage of the early retirement costs to be capitalized that it used in capitalizing all other costs charged to Account 926. (IP Ex. 1.63, pp. 23-24) IP notes that Ms. Hathhorn agreed that IP allocates a portion of A&G costs to construction on the basis of periodic studies as described in Electric Plant Instruction No. 4, that IP used the same percentage to allocate a portion of the severance and early retirement costs to construction that it used to allocate other costs recorded in Accounts 920 and 926 to construction, and that she did not take issue with the percentage used by IP in 2000 to allocate a portion of its A&G costs to construction. (Tr. 311-12) (IP Init. Br., pp. 31-32)

IP concludes that it properly capitalized a portion of the severance and early retirement costs; that given that these costs were properly chargeable to A&G Accounts 920 and 926, it was appropriate to capitalize a portion of these costs on the same basis as all other costs charged to Accounts 920 and 926; and that it properly determined the portion of A&G costs to be capitalized on the basis of special studies, and applied the same percentage to the severance and early retirement costs as to all other costs recorded in Accounts 920 and 926, respectively. (IP Init. Br., p. 32)

(2) Staff's Position

Staff believes that IP's accounting treatment of capitalizing a portion of severance costs is inappropriate because such costs are a one-time period expense which do not add value to IP's plant. Staff's position is that the costs should be expensed in the period incurred. (Staff Ex. 1.0, pp. 15-16) Staff states that it has never disputed that Accounts 920 and 926 are the proper accounts for the severance <u>expense</u>, but the fact that the costs are recorded in the same accounts on the expense side does not mean they should automatically be capitalized. Staff acknowledges that IP has accurately described the methodology supporting its routine, capitalizable charges, but Staff contends that same methodology and principle cannot be applied wholesale to these unique, one-time costs. Staff believes that such treatment violates the USOA since IP's severance costs were not incurred in support of the construction and addition of assets. Staff cites Electric Plant Instruction 3, A (1) and (2) as a source of guidance on proper capitalization. (Staff Init. Br., pp. 29; 32-33)

Staff maintains that severance costs are not labor costs, as they are not costs incurred by utility employees engaged on construction work. Rather, Staff argues, they are costs paid to employees to not engage in any future utility activity, as well as costs of training and outplacement costs, and benefit payout costs to former employees. Staff states that these costs are not defined in the USOA as proper to capitalize as a component of plant. Staff rejects IP's argument that, because severance pay is considered taxable income by the IRS, those costs should be considered wages for regulatory purposes. Staff states that the Commission is not bound by IRS tax rules, but rather by the rules of regulatory accounting found in the USOA and the PUA. Staff argues that regulatory accounting commonly does not agree with the tax code. (Staff Init. Br., pp. 33-34)

Staff argues that the IP has presented no independent evidence to support why severance costs should be capitalized, other than the fact that most other costs recorded in Accounts 920 and 926 are capitalized in part. Staff notes that the USOA requires the amounts capitalized to be based upon the item's reasonable applicability to the plant and not simply to be based upon an arbitrary percentage. Staff cites Electric Plant Instruction 4, A and B in support of this proposition. (Staff Init. Br., p. 34)

Staff argues that even if the Commission were to accept the IP's position that severance pay is a labor charge, severance pay has no reasonable applicability toward construction costs, nor does it have a definite relation to construction. Therefore, Staff contends, it is inappropriate to capitalize the severance costs under the USOA. Staff states that as noted in Electric Plant Instruction 4, the addition to direct construction costs of arbitrary percentages or amounts to cover assumed overhead costs is not permitted. Staff asks the Commission to direct IP to reflect an adjustment to remove the capitalized severance and early retirement costs in future regulatory financial records. (Staff Ex. 1.0, p. 18) (Staff Init. Br., p. 35)

(3) Commission's Analysis and Conclusion

Having considered the accounting analyses presented by IP and by Staff on this issue, the Commission is of the opinion that IP has applied the more appropriate accounting analysis under the USOA, and that it appropriately capitalized a portion of the severance and early retirement costs. The Commission notes that Electric Plant Instructions 3 and 4 provide for the capitalization of general and overhead costs, based on special studies; that IP properly recorded the severance and early retirement costs in Accounts 920 and 926, which are accounts a portion of which are capitalized by IP; and that IP appropriately determined the percentages of costs recorded in these accounts to be capitalized based on special studies. Staff has not provided any persuasive reasoning under the USOA as to why a portion of certain costs recorded in Accounts 920 and 926 would be capitalized whereas other costs recorded in these same accounts would not be. Accordingly, the Commission does not accept Staff's proposed adjustment.

e. Deferred tax debit balances

(1) IP's Position

IP opposes CUB/AG's proposal to remove from the reserve for deferred income taxes the debit balances for four items in the deferred tax accounts, which would have the effect of increasing the amount of the reserve for deferred taxes, and therefore decreasing overall rate base. IP states that CUB/AG witness Effron's rationale for removing the four deferred tax debit balances he chose to remove (the deferred tax debit balances related to accrued pensions and benefits, miscellaneous reserves, vacation pay accrual, and accrued interest on tax liabilities) was that these deferred tax debit balances "are related to reserves, deferred credits, or accrued liabilities that are not recognized in the calculation of rate base." (GCI Ex. 2.0, p. 28; Tr. 409) IP contends that Mr. Effron's proposed adjustment departs from the underlying rationale for deducting the reserve for deferred taxes in determining rate base. IP states that the overall deferred tax reserve consists of numerous individual debit and credit balances relating to book versus tax timing differences that arise for a wide variety of reasons. From a balance sheet perspective, accumulated deferred income taxes support a portion of the utility's assets. IP states that accumulated deferred income taxes are deducted from rate base because they constitute ratepayer-supplied capital, not investor-supplied capital; the theory is that a utility should not be allowed to earn a return on the portion of its assets in rate base that are not supported by investor-supplied capital. IP states that it has not been the Commission's practice to determine the components of the deferred tax reserve to be deducted from rate base on an account-by-account basis; rather, the Commission has simply deducted the entire deferred tax reserve from rate base. Therefore, according to IP, the entire net balance of the accumulated reserve for deferred taxes should be deducted from rate base without adjustment. IP states that in IP's 1989-1990 rate case, Docket 89-0276, the Commission rejected a previous attempt by CUB/AG witness Effron to make a selective exclusion from the deferred tax reserve for rate base purposes. (IP Init. Br., pp. 32-34)

Although contending that CUB/AG's proposed adjustment should be rejected in its entirety, IP also presented IP Exhibit 1.69 which listed deferred tax credit balances for which the related reserves, accruals and so forth are not considered in the development of rate base but which are nonetheless included in the deferred tax reserve that is deducted from rate base. IP states that if the Commission were to accept Mr. Effron's position and remove from the deferred tax reserve the four deferred tax debit balances he removed, the Commission should also remove the deferred tax credit balances listed on IP Exhibit 1.69, to be consistent. IP rejected CUB/AG's argument that one of these credit balances listed on IP Exhibit 1.69, the balance related to amortization of loss on reacquired debt, should be removed from IP Exhibit 1.69 because the ratemaking treatment of the loss on reacquired debt is equivalent to including it in rate base. IP states that the ratemaking treatment of loss on reacquired debt provides for ultimate recovery of the loss on reacquired debt, but not for a return on it.

(2) CUB/AG's Position

CUB/AG contended that IP incorrectly included several deferred tax debit balances in the accumulated deferred income taxes ("ADIT"), because the related accruals are not included in rate base. The four deferred tax debit balance items are the following: (1) the net deferred tax balance related to accrued pensions and benefits; (2) the deferred tax balance related to miscellaneous reserves; (3) the deferred tax balance relating to accruals for vacation pay; and (4) the deferred tax balance related to the interest on tax issues. (GCI Ex. 2.0, pp. 27-29) The total amount of these deferred tax debit balances is $12,072,000. (See Schedule DJE 6.4) Thus, their removal from the net balance of ADIT will reduce the overall rate base by $12,072,000. CUB/AG state that one of the additional debit and credit balances identified on IP Exhibit 1.69, the credit balance related to "Loss on Reacquired Debt," should not have been included, because although the loss on reacquired debt is not included in rate base, the ratemaking treatment for this item is the equivalent of including the unamortized loss on the re-acquisition of debt in rate base. (CUB/AG Init. Br., pp. 12-15)

(3) Commission's Analysis and Conclusion

The Commission declines to adopt the adjustment to the deferred tax reserve proposed by Mr. Effron. The theory behind the deduction of the reserve for deferred taxes in determining rate base is that the reserve for deferred taxes supports a portion of the utility's assets, is customer-supplied not investor-supplied capital, and that the utility should not be allowed to earn a return on the portion of its assets that is supported by customer-supplied capital. The Commission has never determined the deferred income tax reserve deduction from rate base by matching up individual components of the deferred tax reserve against corresponding accruals, reserves and so forth that have been included in establishing rate base. The Commission does not see a reason to begin engaging in that exercise at this time, particularly since it would likely involve numerous debates such as the one between IP and CUB/AG over the deferred tax credit balance for "Loss on Reacquired Debt." Accordingly, CUB/AG's proposed adjustment to remove certain deferred tax debit balances from the overall deferred tax reserve that is deducted from rate base, will not be adopted.

f. Incentive compensation capital adjustment

(1) IP's Position

During the test year, a portion of the incentive compensation that IP paid to its employees was capitalized and charged to construction; the balance was expensed. IP and Staff agreed that if the Commission disallowed any portion of IP's test year operating expense item for incentive compensation, it would be necessary to make a corresponding adjustment to rate base to remove a commensurate amount of capitalized incentive compensation costs. However, in light of the Commission's conclusion with respect to Staff's proposed adjustment to IP's incentive compensation expense, as discussed in Section II.C.3.a of this Order, there is no need for an adjustment to rate base relating to incentive compensation payments. (IP Init. Br., pp. 34-35)

4. Commission's Overall Conclusion on Distribution Rate Base

Giving effect to the adjustments to rate base approved above, the Commission concludes that Illinois Power's distribution rate base for purposes of this case is $909,163,000. The rate base may be summarized as follows:

Item	Amount (000)
Plant in Service	
Distribution Plant	$1,472,356.0
General Plant	201,730.0
Intangible Plant	70,714.0
Accum. Depreciation – Distribution	(577,623.0)
Accum. Depreciation – General	(37,210.0)
Accum. Depreciation – Intangible	(54,664.0)
Net Plant in Service	$1,075,303.0
Adjustments to Rate Base	
Land Held for Future Use	---
CWIP – Not including AFUDC	5,592.0
Dep. Res. – Contrib. Elec. Distrib.	2,870.0
Working Capital	9,960.0
Reserve for Deferred Income Taxes	(180,948.0)
Customer Deposit Balance	(2,044.0)
Customer Advances for Construction	(1,032.0)
Pre-1971 Investment Tax Credits	(538.0)
Total Adjustments to Rate Base	(166,140.0)
Total Rate Base	$ 909,163.0

C. Distribution Operating Income Statement

1. Overview of IP's Proposed Operating Income Statement

Illinois Power proposes the following distribution operating expense statement (Rev. IP Ex. 3.24) (See also IP Init. Br., p. 35):

Item	Amount (000)
Operation and Maintenance	$53,015.0
Customer Accounts Expense	12,163.0
Customer Service and Inform. Expense	4,488.0
Administrative & General Expense	41,682.0

Depreciation Expense – Dist. Plant	33,789.0
Depreciation Expense – General Plant	5,189.0
Amortization Expense – Intangible Plant	7,106.0
Taxes Other Than Income Taxes	33,287.0
Investment Tax Credit Adjustment – Net	(573.0)
Total Operating Expenses	$190,146.0

2. Uncontested Adjustments

Load research project. The operating expenses include an ongoing level of expense necessary in connection with IP's load research project (described in Section II.B.2 above). The annual O&M expense consists principally of telephone charges for cell phones installed on the load research meters to enable the data they collect to be accessed. This adjustment also includes the depreciation expense on the load research meters. This adjustment increases distribution operating expense by $182,000. (IP Ex. 6.1, p. 28; IP Ex.6.5; IP Ex. 1.75; Rev. IP Ex. 3.24, p. 1, col. (5)) (IP Init. Br., pp. 35-36)

CWIP transferred to Utility Plant in Service. In connection with the uncontested rate base adjustment to transfer to plant in service accounts the costs of certain projects that were still recorded in the CWIP accounts at December 31, 2000, but had already been placed in service (see Section II.B.2 above), there are also additional operating expenses, principally for depreciation and taxes other than income taxes. This adjustment recognizes these amounts as plant in service. (IP Ex. 1.1, p. 11) The adjustment increases distribution operating expense by $839,000. (Corrected Rev. IP Ex. 1.7; IP Ex. 1.75; Rev. IP Ex. 3.24, p. 1, col. (7)) (IP Init. Br., p. 36)

Facilities no longer in use. In connection with the rate base adjustment to remove Company facilities no longer in use, there are also reductions to A&G expense, depreciation expense and taxes other than income taxes. This adjustment reduces distribution operating expense by $418,000. (IP Ex. 1.1, pp. 11-12; IP Ex. 2.1, p. 19; IP Exs. 1.29, 1.75; Rev. IP Ex. 3.24, p. 1, col. (8)) (IP Init. Br., p. 36)

Rate case expense. This adjustment provides for the amortization and recovery of the costs of outside services for this rate case over a three-year period, which is the same amortization period allowed for rate case expenses in the 1999 DST Case. This adjustment also provides for recovery of the remaining unamortized balance of expenses from the 1999 DST Case. This adjustment increases distribution operating expense by $494,000. (IP Ex. 1.1, pp. 17-18; IP Ex. 1.16; Rev. IP Ex. 3.24, p. 1, col. (10)) (IP Init. Br., pp. 36-37)

Postal rate increase. This adjustment increases Customer Accounts expense for the amount of the postal rate increase (one cent per letter for first class and bulk mailings) that went into effect on January 1, 2001. This adjustment increases distribution operating expense by $68,000. (IP Ex. 1.1, p. 18; IP Ex. 1.17; Rev. IP Ex. 3.24, p. 1, col. (11)) (IP Init. Br., p. 37)

Insurance expense. This adjustment revises the test year amount of insurance expense in three respects. First, it recognizes premium increases in 2001 for property and liability insurance over 2000. Second, it removes certain one-time credits to nuclear insurance premiums that IP received in 2000, which served to understate the ongoing level of insurance expense. Third, it removes the expense incurred in 2000 for a residual nuclear policy maintained by IP. This adjustment increases distribution operating expense by $2,619,000 in the aggregate. (IP Ex. 1.1, pp. 19-20; IP Ex. 1.18; Rev. IP Ex. 3.24, p. 1, col. (12)) (IP Init. Br., p. 37)

Company use of electricity. Because IP no longer owns generating facilities, it must purchase the electricity it uses at its facilities from third parties. This adjustment provides for the cost of Company use of electricity in distribution operating expenses. The adjustment increases operating expense by $1,127,000. (IP Ex. 1.1, pp. 21-22; Rev. IP Ex. 1.24; Rev. IP Ex. 3.24, p. 2 col. (16)) (IP Init. Br., p. 37)

Pass-through revenue taxes. This adjustment eliminates from distribution operating expense (taxes other than income taxes) $12,067,000 of municipal utility taxes, public utility taxes, Low Income Energy Assistance charges and Renewable Energy Fund charges that IP collects from retail customers as agent for municipal and State governmental authorities. (IP Ex. 1.1, p. 22; IP Ex. 1.25; Rev. IP Ex. 3.24, p. 2, col. (17)) (IP Init. Br., pp. 37-38)

Payroll expense adjustment for wage and salary increases. This adjustment increases distribution operating expense by $1,410,000 to reflect a scheduled 3% union wage increase that was effective July 1, 2001, and a corresponding salary increase for non-union employees provided in 2001. The final adjustment amount incorporates revisions suggested by Staff witness Hathhorn. (IP Ex. 1.1, pp. 22-23; IP Ex. 1.34, p. 29; IP Ex. 1.76; Rev. IP Ex. 3.24, p. 2, col. (18)) (IP Init. Br., p. 38)

FICA expense. This adjustment increases distribution operating expense by $52,000 to reflect the employer's responsibility to match a higher portion of the employees' FICA contributions in 2001 (6.2% of first $80,000 of gross earnings versus 6.2% of first $76,000 of gross earnings in 2000). (IP Ex. 1.1, p. 23; IP Ex. 1.27; Rev. IP Ex. 3.24, p. 2, col. (19)) (IP Init. Br., p. 38)

Dynegy senior executive bonuses. This adjustment reduces distribution operating expense by $7,445,000 to remove the expense of bonuses accrued in 2000 for Dynegy executives that was allocated to IP. (IP Ex. 1.1, p. 24; IP Ex. 1.77; Rev. IP Ex. 3.24, p. 2, col. (21)) (IP Init. Br., p. 38)

Operations compliance program. This adjustment increases distribution operating expense by $77,000 to provide for the amortization over a three-year period of a $230,000 expense that IP incurred for an outside consultant in connection with the initial establishment of its operations compliance program. The operations compliance group will monitor and provide feedback regarding IP's adherence to operating procedures, standards and policies, and define and improve IP's processes for maintaining compliance with these requirements. (IP Ex. 2.1, p. 20; Rev. IP Ex. 3.24, p. 2, col. (22)) (IP Init. Br., pp. 38-39)

Storm damage expense normalization. This adjustment increases distribution operating expense by $581,000 to provide for a normalized level of storm damage expense. The adjustment is based on the difference between actual 2000 storm damage expense and the average expense for the five-year period 1996-2000. (IP Ex. 2.1, pp. 20-21; IP Ex. 2.11; Rev. IP Ex. 3.24, p. 2, col. (23)) (IP Init. Br., p. 39)

"Duke Engineering" litigation expense. This adjustment reduces distribution operating expense by $1,030,000 to remove the expense incurred in 2000 for a litigation matter that arose in connection with IP's ownership of Clinton Power Station. This adjustment was proposed by CUB/AG witness Effron. Consistent with this adjustment, any recoveries IP ultimately realizes in this litigation will also be recorded below the line. (IP Ex. 1.63, p. 25; Rev. IP Ex. 3.24, p. 3, col. (27)) (IP Init. Br., p. 39)

Edison Electric Institute dues attributable to lobbying activities. This adjustment reduces distribution operating expense by $14,000 to remove the portion of IP's dues paid to the Edison Electric Institute that were used for that organization's lobbying activities. This adjustment was proposed by Commission Staff witness Bonita Pearce. (IP Ex. 1.34, p. 30; Staff Ex. 3.0, pp. 5-6; Rev. IP Ex. 3.24, p. 3, col. (28)) (IP Init. Br., p. 39)

Correction to billings from Dynegy under the SFA. This adjustment reduces distribution operating expense by $1,035,000 to reflect a correction to IP's billings from Dynegy for allocated A&G costs. The need for this correction was identified by Staff witness Hathhorn, who pointed out that certain corporate A&G costs were not allocated to IP in 2000 using the correct allocation formula specified in the SFA. (IP Ex. 1.34, p. 30; Staff Ex. 1.0, p. 32; Rev. IP Ex. 3.24, p. 3, col. (30)) (IP Init. Br., pp. 39-40)

Reimbursements to Clinton Power Station employees. This adjustment reduces distribution operating expense by $2,000 to eliminate certain expense reimbursements that were paid in 2000 to Clinton Power Station employees. This adjustment was identified by Staff witness Hathhorn. (IP Ex. 1.34, p. 29; Staff Ex. 1.0, p. 14; Rev. IP Ex. 3.24, p. 3, col. (31)) (IP Init. Br., p. 40)

Metering and billing expense for additional customers. IP accepted an adjustment to test year billing determinants proposed by CUB/AG witness Effron that increased the number of customers by 3,404. (IP Ex. 6.6, pp. 3-4) This adjustment increases customer accounts expense by $33,000 for the additional meter reading and billing expenses that would be incurred as a result of such an increase in the number of customers. (IP Ex. 8.10, pp. 8-9; IP Ex. 8.13; Rev. IP Ex. 3.24, p. 3, col. (32)) (IP Init. Br., p. 40)

Payments to State of Illinois Energy Efficiency Fund. This adjustment reduces Customer Service and Information expense by $446,000 to remove IP's pro rata portion of the annual aggregate $3,000,000 contribution that must be made by sellers of electricity to the State's Energy Efficiency Trust Fund. Staff witness Pearce identified the need for this adjustment. IP will instead impose a per-kWh charge in those DST-related tariffs in which it sells electricity (i.e., Rider PPO and Rider ISS) to recover the portion of this payment attributable to energy sales to delivery services customers. (IP Ex. 1.34, p. 30; Staff Ex. 3.0, pp. 6-7; IP Ex. 5.11, p. 2; Rev. IP Ex. 3.24, p. 3, col. (33)) (IP Init. Br., p. 40)

Illinois Energy Association dues. This adjustment reduces distribution operating expense by $72,000 to remove dues paid to the Illinois Energy Association, as recommended by Staff witness Pearce. However, as discussed in Section II.C.3.h below, the Company contests the remainder of Ms. Pearce's adjustment for contributions to community organizations. (IP Ex. 1.63, pp. 25, 41-42; IP Ex. 1.73; Rev. IP Ex. 3.24, p. 3, col. (34)) (IP Init. Br., pp. 40-41)

3. Contested Adjustments

a. Incentive compensation expense

(1) IP's Position

It is IP's position that incentive compensation payments to its employees are a reasonable and necessary business expense incurred in providing service to its customers that must be included in setting rates. IP's proposed test year distribution operating expenses include $5,159,000 of expense for payments to employees under IP's incentive compensation program. This is the electric distribution portion of IP's total test year incentive compensation expense. IP states that it is entitled to have its rates set so as to allow it a fair opportunity to recover its reasonable and necessary expenses, and that to allow no recovery of incentive compensation expense, as proposed by Staff, or less than 15% of the test year expense, as proposed by CUB/AG, would be arbitrary and would deny IP recovery of a reasonable and necessary expense. (IP Init. Br., pp. 41-42)

IP states that incentive compensation programs are commonly used in American business today as part of an entity's total compensation program, and that incentive compensation programs provide a cost-effective way to attract and retain qualified employees, particularly employees in those job categories for which the employment market is highly competitive. IP has had an incentive compensation program in place as part of its overall compensation structure since at least 1991, and has made incentive compensation payments to employees in each year in this period. (Rev. IP Ex. 10.1, p. 2) IP states that incentive compensation payments now constitute a material part of IP's overall compensation expense. (IP Init. Br., p. 42)

IP explained that for 2000 and 2001, the basic structure of IP's incentive compensation program for non-union employees had these components: First, the overall funding of the program was based on the extent to which IP met one or more pre-established corporate performance targets of the Company or its corporate parent, Dynegy (and therefore, necessarily, of Dynegy's other affiliated companies). Second, the individual incentive compensation payments to non-union employees from the overall fund were based on the extent to which employees met individual and/or departmental goals and objectives. Individual employee goals established to use in determining the extent of the employee's incentive compensation payment from the overall pool include budgetary and cost control objectives, safety, reliability and project completion objectives, and skills development objectives. IP also considered the labor market for each category of employees in determining individual employee payments, thereby further enhancing the usefulness of the program in retaining qualified employees in fields for which the labor market is highly competitive. (Rev. IP Ex. 10.1, pp. 3, 14) In addition, IP had a separate program for determining incentive compensation payments to its union employees, which had been negotiated in the current collective bargaining agreement. (Id., pp. 3, 13) (IP Init. Br., pp. 42-43)

IP states that in its experience, the incentive compensation program is an important and useful tool in attracting and retaining high-quality employees, particularly for positions for which there is a highly competitive employment market. IP indicates that positions for which the labor market has been highly competitive in recent times include electrical engineers, accounting professionals, information technology ("IT") professionals, and lineman candidates. (Rev. IP Ex. 10.1, p. 8) IP states that it must attract and retain qualified employees in these and other fields if it is to meet its service obligations and requirements in a safe and reliable manner, and must offer competitive compensation packages to prospective and current employees in order to attract and retain them. (Id.) Further, the Company notes that it does not just compete with other regulated utilities for employees; rather, it competes for employees with other businesses in the energy industry as well as with other unregulated businesses in general. (IP Ex. 10.2, pp. 5-7; Tr. 331-32) In addition, IP notes that it has experienced difficulties in attracting employees to live and work in Decatur and other central Illinois locations. (Rev. IP Ex. 10.1, pp. 7-8) IP states that an incentive compensation plan enables it to offer prospective and current employees the opportunity for additional compensation beyond their base salary and wage amounts, with upside potential based on corporate and individual performance. (Id., p. 7) Moreover, because incentive compensation programs are widespread, prospective employees considering whether to join IP, and current employees considering whether to leave IP for other employers, may consider IP's program and compare it to those offered by other prospective employers. (Id.) In this regard, IP witness Ellen Hearn testified that the fact that IP's incentive compensation program is based in part on financial performance of its parent, Dynegy, is an advantage because it enhances the usefulness of incentive compensation as a tool to attract and retain qualified employees. Ms. Hearn testified that prior to the merger with Dynegy, prospective and existing employees may have seen the upside potential from IP's incentive compensation program as limited because it was solely dependant on the financial performance of a regulated utility, IP. In contrast, the ability to base the program funding on the financial performance of Dynegy enables IP to offer employees the opportunity to participate in the upside potential of a diversified Fortune 500 company that is a recognized leader in several businesses. (Rev. IP Ex. 10.1, pp. 8-9; IP Ex. 10.2, p. 3) (IP Init. Br., pp. 44-45)

IP states that another reason its incentive compensation program is valuable is that it can be structured so as to focus employees' attention and performance on business issues that are critical to the Company at the time. IP can focus the employees' efforts and attention on the Company's current business needs by the selection of the corporate goals and objectives on which overall incentive compensation funding and/or payments to individual employees will be based. IP states that the ability to modify the bases for funding and awarding incentive compensation from year to year is a strength of the program. (Rev. IP Ex. 10.1, pp. 5-6) (IP Init. Br., p. 45)

IP also states that use of incentive compensation as part of the its overall compensation package enables IP to offer additional compensation to attract and retain employees, and to focus employees' attention on corporate or individual business needs and objectives of current importance, without locking in higher levels of base pay and related benefits costs. IP witness Hearn explained that when employees receive annual wage and salary increases, they tend to expect the new level of pay each year, and to view the annual pay increases as a locked-in floor to their compensation. She stated that such expectations, however, are not associated with incentive compensation payments. As a result, the incentive compensation program can be used to reward employees for strong corporate performance and/or strong individual performance in a particular year without creating the expectation that the same level of pay will be received in future years. (Rev. IP Ex. 10.1, p. 10) Ms. Hearn also testified that pension and benefit program costs are tied to the employees' base wage and salary levels, but are not affected by incentive compensation payments. Therefore, incentive compensation payments do not result in increased pension and benefits costs to IP. She testified that in contrast, a corresponding amount of employee base pay would result in additional pension and benefit program costs. (Id., p. 11) (IP Init. Br., p. 46)

IP states that the benefits of the incentive compensation program to IP also result in benefits to its customers, for these reasons: First, the incentive compensation program enhances IP's ability to attract and retain qualified employees, which benefits customers. Second, the desire to achieve both the overall corporate performance objectives, which determine the overall amount of funding for the program, and the individual performance goals and objectives, which determine the individual employee's payout, help motivate employees to achieve a higher level of performance. Individual goals are based on objectives such as meeting budget and cost control targets, safety, reliability and project completion targets, and skills development objectives, all of which can benefit customers in terms of maintaining or improving levels of safety and reliability, or controlling cost levels and thereby deferring future rate increase requests. Third, the incentive compensation program addresses these objectives without requiring increases in base pay and related pension and benefits costs, thereby helping to reduce the need for increases in costs that in the long run would need to be reflected in customer's rates. (IP Ex. 10.1, pp. 11-12) (IP Init. Br., pp. 46-47)

IP notes that the Commission has denied recovery of incentive compensation expense in a number of prior cases, generally citing the same set of generic reasons. IP states that although Staff witness Hathhorn did not dispute that an incentive compensation program provides benefits for the Company (Tr. 330), she relied on these prior cases in support of her adjustment. IP urges the Commission to take a fresh look at the entire topic of incentive compensation, its importance in IP's overall compensation structure, and the benefits it provides to both IP and its customers. IP urges the Commission to recognize that incentive compensation is a reasonable and necessary business expense and that, as a result, some provision for incentive compensation costs must be allowed in setting rates. (IP Init. Br., p. 43)

IP opposes the adjustments proposed by Staff and CUB/AG which would eliminate or substantially reduce the amount of incentive compensation expense allowed in setting rates. IP states that the principal objections raised by Ms. Hathhorn to including incentive compensation expense in the revenue requirement do not warrant disallowing recovery of this reasonable and necessary business expense. (IP Init. Br., p. 47)

As to Ms. Hathhorn's first objection, that the program funding is determined by the extent to which corporate financial targets of IP and Dynegy (and therefore of other Dynegy affiliates) are achieved, which benefits shareholders, not customers, IP states that focusing on the fact that the program is funded based on the achievement of overall corporate financial objectives and misses the point. IP states that corporate financial performance is simply the overall target that is used to determine the funding of the overall incentive compensation pool for distribution. IP states that the incentive compensation program benefits customers because it motivates and focuses employees to control costs and meet budget objectives (to help increase the funding of the overall pool), it enhances IP's ability to attract and retain qualified employees, it enables IP to provide market-based compensation without locking in base pay increases or incurring related pension and benefits costs, and it motivates employees to meet the individual employee goals (on which individual payments are based) that stress safety, customer service, reliability and cost control. (IP Ex. 10.2, pp. 1-2) IP notes that CUB/AG's opposition to including a substantial portion of the test year incentive compensation expense in setting rates is based on this same objection. (IP Init. Br., p. 48)

As to Ms. Hathhorn's second objection, that including incentive compensation expense in setting rates leaves customers "unprotected" because if the same level of incentive compensation expense is not incurred in a subsequent year, customers' rates will reflect a cost item the Company does not incur, IP states that the risk perceived by Ms. Hathhorn that in a future year no incentive compensation payments will be made is belied by the facts that (1) IP has made incentive compensation payments to its employees for every year since 1991 (Rev. IP Ex. 10.1, p. 2), and (2) as described above, incentive compensation programs are now commonplace among American businesses, and an integral part of IP's overall compensation structure. IP also contends that the risk that in a future year an expense amount that was included in setting rates will not be incurred, or will be incurred in lesser amount, whether through the impact of external forces or through intentional management action, is by no means unique to incentive compensation costs. IP notes that between rate cases, many other costs that were included in setting rates can be reduced, either through management action or the impact of external forces. IP concludes that the "ratepayer protection" argument does not justify denying recovery of incentive compensation costs. (IP Init. Br., pp. 48-49)

IP also states, however, that its jurisdictional amount of incentive compensation expense for 2000 was the highest amount in the five-year period 1996-2000. (IP Ex. 1.34, p. 42; IP Ex. 1.47) IP acknowledges that the Commission might conclude that the 2000 expense amount was unusually high and should be normalized in some manner. IP states that to that end, it is offering four alternative adjustments to incentive compensation expense (described below) that would provide for a lesser amount of incentive compensation expense in the test year distribution revenue requirement than the actual 2000 amount. (IP Init. Br., p. 49)

As to Ms. Hathhorn's third objection, that based on the historical year-to-year variation in incentive compensation payments, it is not possible to determine a "normal" amount of incentive compensation expense, IP states that it should be no more difficult to determine a "normal" amount of incentive compensation expense for ratemaking purposes than it is for other reasonable and necessary operating expenses that tend to vary (both up and down) from year to year. IP notes as an example that in this case, it has proposed, and the parties have accepted, an adjustment to increase the actual 2000 level of storm damage O&M expense to a "normal" level based on a five-year average of storm damage expenses. IP notes that the annual amounts of storm damage direct expense it incurred over the five years 1996-2000 have varied widely from year to year, with the amount of expense incurred in the highest year (1998) being more than three times the amount of expense incurred in the lowest year (2000). (IP Ex. 2.11) IP states that the highly variant nature of this expense item has not been advanced as a reason to allow no recovery. IP states that there are standard ratemaking techniques that can be used to develop a normalized level of incentive compensation expense for ratemaking purposes. IP points out that it has proposed several alternative adjustments reflect such techniques. (IP Init. Br., pp. 49-50)

IP notes that Ms. Hathhorn also stated a fourth objection that "deficiencies cited in prior Commission orders disallowing the Company's [incentive compensation] expense have not been addressed." (Staff Ex. 1.0, p. 27) IP states that these "deficiencies" are essentially the same points as Ms. Hathhorn's first and second objections that are discussed above.

IP concludes that the record on this issue shows that: (1) incentive compensation programs are commonly included in the overall compensation programs offered by American businesses, both regulated and unregulated, with which IP competes to attract and retain qualified employees; (2) IP has had an incentive compensation program in place since at least 1991, and has made incentive compensation payments to employees for each year of this period; (3) both IP and its customers receive significant benefits from the use of an incentive compensation program, and (4) incentive compensation payments to employees are a reasonable and necessary business expense. IP contends that incentive compensation expense is a common, reasonable and necessary cost of providing service, for which the rates established in this case should be designed to provide recovery, and that allowing little or no recovery of any incentive compensation costs would be arbitrary and unsupportable. (IP Init. Br., p. 50)

IP also offered four alternative adjustments to test year incentive compensation expense, in response to concerns raised by Staff witness Hathhorn that including the test year jurisdictional incentive compensation expense in the revenue requirement raises "ratepayer protection" issues. IP states that these alternatives would provide for a lesser amount of recovery than the full test year amount but would still recognize the importance of including some component in the revenue requirement for this reasonable and necessary business expense. IP's first alternative is to allow the five-year average (1996-2000) of its jurisdictional incentive compensation expense. This approach would reduce the jurisdictional expense from the test year actual amount ($5,159,000) to the five-year average amount ($2,876,000). (IP Ex. 1.47) IP states that by normalizing the level of incentive compensation using a five-year average, there is a much smaller likelihood that the level of incentive compensation paid out by IP in a particular year will be less than the level of expense recovered from customers through rates. (IP Ex. 1.34, p. 43; IP Ex. 1.63, p. 31) (IP Init. Br., p. 51)

IP's second alternative is to allow 50% of the test year amount of incentive compensation expense; this adjustment would reduce the amount of incentive compensation expense included in jurisdictional operating expense from the actual test year amount, $5,159,000, to $2,579,000. (IP Ex. 1.48) IP states that by allowing only one-half of the actual 2000 incentive compensation expense, the Commission would create a sharing of incentive compensation costs between customers and shareholders, while still recognizing that incentive compensation is a reasonable and necessary business expense that should be reflected in setting rates. IP states that this approach would also reduce the likelihood that in a future year, IP will pay less in incentive compensation to its employees than is reflected in its rates. IP also notes that to the extent IP meets the financial and other objectives of the incentive compensation program in a particular year and pays a larger amount of incentive compensation to its employees, shareholders will bear the additional expense. (IP Ex. 1.34, pp. 43-44; IP Ex. 1.63, pp. 31-32) (IP Init. Br., p. 51)

IP's third alternative adjustment is to allow the budgeted amount of incentive compensation for 2001. This approach would reduce the jurisdictional amount of incentive compensation expense included in the revenue requirement from $5,159,000 to $4,095,000. (IP Ex. 1.49) IP states that this approach also addresses the "ratepayer protection" issue because IP's budget assumes less than full achievement of the program's financial objectives and therefore less than the maximum payments to employees. IP notes that as with alternative 2, if IP does better in terms of achieving the program's financial objectives, the resultant additional expense would be borne by shareholders. IP also points out that this approach ties the amount of cost included in the revenue requirement to the most current (2001) incentive compensation program. (IP Ex. 1.34, p. 44; IP Ex. 1.63, p. 32) (IP Init. Br., pp. 51-52)

IP's fourth alternative adjustment is to include an amount representing additional base pay IP would need to pay its employees if it did not have an incentive compensation program. IP witness Ms. Hearn estimated that if IP were to eliminate the incentive compensation program, increases of 10-15% in base pay levels would be necessary for IP to remain competitive in the labor markets, with higher increases in this range needed for those job categories that are more difficult to fill. (Rev. IP Ex. 10.1, pp. 12-13) She calculated that this would translate to additional expense for base wages and associated pension and benefits costs of approximately $6.98 million, of which the jurisdictional distribution component would be $3,227,160 (IP Ex. 1.50), as compared to the actual jurisdictional test year amount of $5,159,000. (IP Init. Br., p. 52)

In its Reply Brief, IP indicated that Staff's objections to the four alternatives IP had proposed were conflicting and unpersuasive. IP also stated that another acceptable alternative would be to use the average of the jurisdictional incentive compensation expense for the three years 1998-2000, which as calculated by Staff in its Initial Brief is $4.8 million. (IP Rep. Br., pp. 31-32)

(2) Staff's Position

Staff proposes to disallow $6,077,000 in operating expenses and $625,000 in rate base related to IP's incentive compensation plan, based on several reasons: First, the plan benefits shareholders, not ratepayers; the plan is heavily dependent on achievement of IP's and its affiliates' financial goals, which solely benefit shareholders, not ratepayers. (Staff Ex. 1.0, pp. 27-28 and Staff Cross Ex. 3) Second, there is no ratepayer protection in the event the goals are not met, since even if no cost were incurred by IP, ratepayers still would fully fund the plan. (Staff Ex. 1.0, p. 28) Third, the plan changes annually and therefore it is impossible to determine a "normal" level of plan expense for the test year. (Staff Ex. 1.0, p. 30) Finally, the deficiencies cited in prior Commission orders disallowing IP's incentive compensation expense have not been addressed. (Staff Ex. 1.0, pp. 30-31) Staff contends that by including the incentive compensation expense in the revenue requirement in this case, ratepayers pay for IP's achievement of the nonutility goals. Staff argues that these goals do not benefit the ratepayers and therefore IP should fund the attainment of these goals. (Staff Ex. 1.0, pp. 27-28) Staff contends that IP has not presented evidence to demonstrate that there is a direct relationship between Dynegy, Inc.'s earnings success and benefits to delivery services ratepayers. (Staff Ex. 19.0, p. 18) (Staff Init. Br., pp. 35-37)

Staff also contends that basing incentive compensation goals on financial performance creates a circularity problem, in that the more money included in IP's rates for incentive compensation, the easier it will be for Dynegy, Inc. to meet its earnings goals. Staff contends that IP ratepayers directly impact Dynegy, Inc.'s ability to meet its earnings targets, but receive no direct benefit, and that this occurs independent of whether or not IP's employees are "motivated." (Staff Ex. 19.0, pp. 18) Staff says that the Commission reached this conclusion in a prior IP case, Docket No. 93-0183. (Staff Init. Br., p. 37)

Staff states that it did not review the individual employee goals, as these would be voluminous and do not directly affect the incentive compensation expense, since payout is based upon corporate rather than individual goals. (Staff Ex. 1.0, p. 29; Staff Cross Ex. 3) Staff states that while the individual goals may determine how incentive compensation is earned by employees, earnings are still the driving force behind actual payments. On the topic of employee motivation by the plan, Staff also questions whether IP's financial performance is a significant component of Dynegy's financial performance. Staff also notes that IP has not performed analyses to identify reduced costs it experienced during 2000 which can be directly linked to the incentive compensation program. (Staff Ex. 19.0, pp. 19-20) Staff states that if costs savings were a key factor in the incentive compensation program, an analysis would be performed by IP and be part of the evaluation of the program's effectiveness. (Staff Ex. 19.0, p. 20) (Staff Init. Br., pp. 37-39)

Staff argues that ratepayers are not protected in the event that IP fails to achieve the financial goals and incentive compensation payments are not made. Staff states that there is no mechanism to protect ratepayers should IP not achieve its 2000 level in the future; if the cost of incentive compensation is allowed to be recovered through rates, ratepayers will pay the cost of incentive compensation whether or not IP incurs it. Staff notes that the Commission expressed concern about this issue in IP's 1999 DST Case as well as in CILCO's 1999 DST case. Staff states that its objection to recovering incentive compensation expense through rates is not based on the assumption that there are no benefits to the program, but rather that ratepayers do not benefit nor are they protected enough to bear the cost, and must pay the test year expense whether or not IP incurs it in future years. (Staff Ex. 1.0, pp. 26-27; Staff Ex. 19.0, p. 21) (Staff Init. Br., pp. 39-40)

Another objection stated by Staff is that due to a lack of comparable historical data, IP is unable to demonstrate that the proposed test year level of incentive compensation expense is reflective of a "normal" level. Staff states that there is a wide variance among the actual jurisdictional expense for the years 1998, 1999 and 2000 and the budgeted expense for 2001. Staff contends that as a result, it is not able to determine future payouts based upon historical data. (Staff Ex. 1.0, p. 30) Staff states that the historical results vary so greatly that even using an average of the 1998 through 2000 amounts does not appear to produce a valid result, especially when compared to the IP's 2001 budgeted incentive compensation amount. (Staff Ex.

19.0, pp. 21-22) Staff also argues that the increase in the budgeted amount highlights an inherent problem of basing the payout on earnings, that the expense is rising even though the number of employees is decreasing. (Staff Init. Br., pp. 40-42)

Staff states that the Commission concluded that incentive compensation expense should be disallowed in IP's 1999 DST Case as well as in the following other cases: MidAmerican Energy Company, Docket No. 99-0534 (July 11, 2000); Illinois Power Company, Docket Nos. 93-0183 (April 6, 1994) and 91-0147 (February 11, 1992); Central Illinois Light Company; Docket Nos. 99-0119/99-0131 (Consolidated) (August 25, 1999), and 94-0040 (December 12, 1994); Consumers Illinois Water Company, Docket Nos. 95-0641 (October 23, 1996) and 95-0307/95-0342 (Consolidated) (May 8, 1996); Citizens Utilities Company of Illinois, Docket No. 94-0481 (April 6, 1994); and Central Illinois Public Service Company and Union Electric Company, Docket No. 00-0802 (December 11, 2001). Staff argues that the Commission has recognized that incentive plans may be a part of a utility's compensation package but that it does not follow that such plans have to be included in operating costs. (Staff Init. Br., pp. 42-43)

Staff also notes that IP cited several outside surveys and articles that show that incentive compensation is common today, but that these provide no evidence as to why incentive compensation costs should be recovered from monopoly ratepayers. (Staff Init. Br., p. 43)

It is Staff's position that the four alternative adjustments presented by IP should also be rejected. Staff contends that although IP's first proposal, to normalize the level of expense over a five-year period, is intended to address Staff's ratepayer protection concern by smoothing out the yearly expense variances; Staff's recommended disallowance is not solely due to the expense variances, but also the plan's dependence on financial goals. Staff argues that this alternative does not address the problems implicit in the structure of the program. Staff contends that IP's second alternative, to include 50% of the year 2000 expense in the test year, was not supported by any explanation of the 50% figure, other than that it was selected to create a 50-50 likelihood that the actual payments during the years that the rates set in this case will be in effect will be greater than or less than the amount of incentive compensation expense in the revenue requirement. Staff contends that the 50% split is arbitrary and has not been approved by the Commission in the past. Staff fears that this alternative could set a dangerous precedent of using a formula method to resolve controversial issues. Staff does not find IP's third alternative, to include the budgeted level of incentive compensation expense for 2001, acceptable because IP chose to file a historical test year, not a future test year which would carry with it additional requirements to verify the budgeting process. Finally, Staff objects to IP's fourth alternative, to provide additional base pay expense as if IP had eliminated its incentive compensation program, because the calculation is too contrived and estimated to be preferred over actual year 2000 expense data. Staff also notes that none of IP's proposed alternative adjustments in IP Exhibits 1.47 through 1.50 contains adjustments to reflect the rate base or payroll tax effect of the proposals, and that if any of these alternatives were accepted, such additional adjustments to payroll taxes and rate base would have to be made. (Staff Ex. 19.0, pp. 25-27) (Staff Init. Br., pp. 43-46)

(3) CUB/AG's Position

It is CUB/AG's position that IP's incentive compensation related to Earnings Before Interest and Taxes ("EBIT") should be excluded. CUB/AG note that during 2000, IP had two incentive compensation programs, one union and one non-union. The typical goals for the union incentive compensation program focused on safety and reliability objectives, which benefit everyone, including customers. Accordingly, CUB/AG agree that it is reasonable to include the delivery service portion of this expense in the cost of service. However, the 2001 incentive compensation program for non-union employees will be based on EBIT. CUB/AG believe that the incentive compensation related to EBIT should be excluded from the delivery service revenue requirement, because increasing EBIT is a shareholder-oriented goal, not a customer-oriented goal. (GCI Ex. 4.0, p. 9) CUB/AG state that including incentive compensation related to EBIT in the revenue requirement would, in effect, require customers to reward company management on a contingency basis for getting them to pay higher rates. CUB/AG contend it should be shareholders, not customers, that bear the cost of the incentive compensation related to EBIT. CUB/AG state that the total incentive compensation included by IP in test year expenses is $5,159,000, the incentive compensation focused on safety and reliability is $596,000, and therefore, the remaining expense, $4,563,000, should be eliminated from the delivery services revenue requirement. (GCI Ex. 4.0, p. 9) (CUB/AG Init. Br., pp. 16-17)

(4) Commission's Analysis and Conclusion

Based on its review of the record, the Commission concludes that IP's actual test year jurisdictional incentive compensation expense should be included in distribution operating expense for purposes of setting delivery services rates in this case. The record establishes that IP's use of an incentive compensation program as part of its overall compensation program is consistent with the practices of many regulated and unregulated businesses with which IP must compete to attract and retain qualified employees. The record shows that IP's use of an incentive compensation program gives it an additional tool to use in competition with other prospective employers to attract and retain qualified employees, which IP must be able to do in order to provide safe, reliable and efficient service to its regulated customers. In addition, the record shows that IP uses its incentive compensation program to focus its employees on particular business needs and objectives of the Company. An integral part of IP's incentive compensation program is the establishment of individual employee goals the achievement of which determines whether the employee receives any payments from the incentive compensation pool. The individual employee objectives include safety, reliability, budget and cost control, project completion and skills development objectives. In addition, use of the incentive compensation program enables IP to provide this component of employee compensation without locking in annual base pay increases and without the attendant additional pension and benefits costs that would accompany additional base pay to employees. The Commission believes that all of these features are beneficial to customers as well as to the Company. For all these reasons, the Commission concludes that IP's incentive compensation expense is a reasonable and necessary business expense and that IP should be allowed to recover the jurisdictional portion of this expense in its delivery services rates.

The Commission acknowledges that Staff's and CUB/AG's opposition to the inclusion of the incentive compensation expense in rates is based on factors which the Commission has cited in prior orders in denying recovery of incentive compensation costs. The Commission is persuaded, based on the record, that these considerations do not warrant disallowance of incentive compensation costs in this case. The Commission notes that IP has an established track record of making incentive compensation payments to its employees in every year since 1991. In addition, with respect to the argument that customers would have to pay for incentive compensation costs in their rates in future years even if IP does not incur those costs, or incurs them at a lower level, there is no reason to distinguish incentive compensation costs from any other expense that is included in setting rates in this regard. Finally, while the Commission agrees that shareholders benefit if IP and its parent company achieve higher earnings, there are sufficient benefits to customers as well, and in any event, the incentive compensation costs have been shown to be a reasonable and necessary business expense for IP. Therefore, Staff's and CUB/AG's adjustments will not be accepted.

b. Severance and early retirement costs

(1) IP's Position

IP proposes adjustments relating to the fact that during 2000, it reduced its work force by 297 employees. IP made severance payments to some of the employees and induced others to leave the Company by offering early retirement benefits. Of the electric distribution portion of the total severance and early retirement costs, $15,083,000, $5,264,000 was early retirement costs, $718,000 was outplacement, medical and insurance costs, and $8,799,000 was severance pay. (IP Ex. 1.71) IP proposes to (1) reduce test year expenses by the amount of the salaries and wages (including related pension and benefits expense and payroll taxes) paid to these employees during 2000 prior to their departure from IP, (2) remove the actual amount of severance and early retirement expense from the distribution revenue requirement, and (3) amortize and recover the jurisdictional portion of the severance and early retirement program costs over a five-year period. (IP Ex. 1.1, p. 23; Corrected Rev. IP Ex. 1.28) IP states that the net effect of these adjustments is to reduce distribution operating expense by $14,107,000. (Corrected Rev. IP Ex. 1.28; Rev. IP Ex. 3.24, p. 2, col. (20)) (IP Init. Br., pp. 52-53)

IP notes that Staff accepts IP's adjustment to remove the expense for the payroll, pensions and benefits paid to the terminated employees in 2000, and the related payroll taxes, but opposes any recovery of the severance and early retirement costs. It is IP's position that it should be allowed to recover the severance and early retirement costs it incurred to effectuate a work force reduction and achieve the attendant savings which are being passed on to customers in this case. (IP Init. Br., p. 53)

IP acknowledges that, as a general matter, in the recent merger cases cited by Staff, the Commission denied recovery of merger "transaction costs", including in some of those cases employee termination costs. IP states that in earlier cases, the Commission allowed recovery of severance costs incurred in connection with mergers, citing <u>Central Tel. Co. of Illinois</u>, Docket 93-0252 (May 11, 1994), 1994 Ill. PUC LEXIS 206, *18-*22. IP also points out that in two of the four orders cited by Staff, recovery of employee severance costs does not appear to have been at issue. Specifically, IP states that in <u>Illinois-American Water Company, Citizens Utilities Company of Illinois and Citizens Lake Water Company</u>, Docket 00-0476 (May 15, 2001), the only merger-related cost that the applicant sought to recover was the acquisition adjustment or merger premium paid to the acquired company. (Id., pp. 6, 38-39) In GTE Corporation and Bell Atlantic Corporation, Docket 98-0866 (Oct. 29, 1999), the only merger-related costs mentioned were banker and brokerage fees, legal fees, and accounting fees. (Id., p. 41) IP also points out that it is not readily apparent from the orders that involved employee termination costs what the Commission's underlying rationale was for lumping employee severance costs with other costs, such as investment banker fees, legal and accounting fees, printing and other costs for preparation of registration statements and other communications to shareholders, and similar costs that must be incurred to actually close the merger transaction, as "merger transaction costs" that should not be recovered. IP notes that in contrast, in the Central Telephone case cited above, the Commission denied recovery of "merger transaction costs", which it identified as "the one-time costs incurred to legally consummate the merger . . . included in these costs are banker fees, legal fees, accounting fees and proxy costs"; the Commission then separately discussed and allowed recovery of a portion of the applicant's employee severance costs. IP further argues that the Commission has authority to allow recovery of costs incurred in accomplishing a merger under 220 ILCS 5/7-204(c). (IP Init. Br., pp. 53-54)

IP contends that it incurred severance and early retirement costs in the test year specifically to achieve a reduction in ongoing costs that is being passed on to customers in setting rates in this case. (IP Ex. 1.34, pp. 36-37, 41; IP Ex. 1.63, pp. 27-28) IP also contends that Staff witness Hathhorn's reference to the severance and early retirement costs as costs "incurred to produce an ownership change" (Rev. Staff Ex. 10.0, p. 9), is not accurate factually (see IP Ex. 1.63, p. 28), and in any event does not seem relevant. IP points out that Ms. Hathhorn acknowledged that she had not read the Illinova-Dynegy merger agreement, and that she did not know if payment of severance and early retirement benefits to the terminated employees was a condition to the closing of the merger. (Tr. 306-07) Accordingly, IP believes that the more appropriate analogy here is to prior orders in which the Commission allowed IP to recover the costs of an early retirement program (Dockets 89-0276 and 91-0147) and a "re-engineering" program (Docket 93-0183) that led to reductions in operating expenses. (IP Ex. 1.34, pp. 37-38) More generally, IP maintains that it should be allowed to recover the severance and early retirement program costs over a five-year period because these costs were incurred to achieve savings that will far exceed the costs that are being passed on to customers through a reduction in the distribution revenue requirement in this case. (IP Init. Br., pp. 54-55)

IP emphasizes that, as a result of reducing its work force by 297 employees during 2000, it will save both the compensation that was actually paid to these employees before they left IP, plus the balance of their annual compensation (as well as increased salary, benefits and related costs that might have been incurred in future years as the employees received pay raises and other employee-related costs increased). IP emphasizes that the total annualized savings resulting from elimination of the 297 employees are \$25,502,000 for the entire Company; the jurisdictional electric distribution portion of the savings are \$14,765,000. These savings are being fully reflected in the establishment of the distribution revenue requirement in this case. IP states that against these savings, it is requesting to include \$3,017,000 in the distribution revenue requirement to recover the jurisdictional portion of the severance and early retirement costs. IP asserts that the annual savings from the severance and early retirement program exceed the annual amortization of the costs of the program, by a factor of almost five times. (IP Ex. 1.63, pp. 27-28; IP Ex. 1.70) IP states that in light of the cost savings produced, there would seem to be no principled basis for disallowing recovery of the severance and early retirement program costs over an amortization period as proposed by IP. (IP Init. Br., pp. 55-56)

IP contends that Staff's other argument for disallowing recovery of the severance and early retirement program costs, i.e., that in Docket 99-0419, in which the Commission approved the gas utility aspects of the Illinova-Dynegy merger, IP voluntarily committed not to seek recovery of the gas jurisdictional portion of any merger transaction or implementation costs, does not warrant disallowing these costs in this case. IP states although asked in Docket 99-0419, it did not similarly commit not to seek recovery of any merger transaction costs from electric delivery services customers. (IP Ex. 1.34, pp. 39-40; IP Ex. 1.46) IP states that it is not "inconsistent" for the severance and early retirement program costs to be included in electric delivery services rates even though they will not be included in IP's gas utility rates because gas rates were last set in 1994, and IP has no plans to file a gas rate case; therefore, it is unknown when IP's gas utility customers will benefit directly from the reduction in employee levels implemented in 2000. In contrast, in 1999, IP knew it would have another DST rate case in 2001, i.e., this case, in which reduced employee levels and associated wage and salary and pension and benefits costs would be reflected in setting delivery services rates. IP states that since electric delivery services customers will be receiving this benefit, the rates they pay should also reflect amortization and recovery of the severance program costs that were incurred to achieve this benefit. IP argues that Staff witness Hathhorn acknowledged these distinctions between electric and gas customers during cross-examination. (Tr. 326-28) IP states that given these facts and circumstances, it is by no means unreasonable for the jurisdictional electric distribution portion of the severance and early retirement program costs to be recovered through delivery services rates, even though IP voluntarily committed not to seek recovery of any merger transaction costs in its gas rates. (IP Init. Br., pp. 56-57)

IP rejects CUB/AG's proposal that the 5-year amortization period for the severance and early retirement program should be deemed to have commenced in 2000. IP states that this approach could result in less than full cost recovery. IP states that it should be allowed the opportunity for full recovery of the jurisdictional portion of the severance and early retirement costs because after the recovery of the costs is complete, customers will continue to benefit from the cost savings that resulted from the work force reduction. (IP Rep. Br., pp. 37-38)

(2) Staff's Position

Staff witness Hathhorn proposed to disallow $3,057,000 in operating expenses and $4,928,000 in rate base to deny severance costs because Staff believes that such costs are non-recurring, non-operational transactional costs of the Company's merger with Dynegy, Inc. (Staff Ex. 19.0, Schedule 19.8) Staff argues that these costs were incurred in order to effectuate a change in Company ownership, rather than as a result of utility operations. (Staff Ex. 1.0, p. 15) Staff asserts that the Commission has denied cost recovery of all transactional costs in recent mergers, including the SBC/Ameritech merger proceeding, Docket No. 98-0555; as well as GTE/Bell Atlantic, Docket No. 98-0866 (October 29, 1999); Illinois American Water Company/Citizens Utility Company of Illinois, Docket No. 00-0476 (May 15, 2001); and Illinois American Water Company/Northern Illinois Water Company, Docket No. 99-0418 (May 29, 2000). (Staff Ex. 1.0, p. 17) Staff contends that in contrast, the Commission orders relied on by IP are unrelated to the present facts. Staff states that neither Docket 89-0276, Docket 91-0147, or Docket 93-0183, all cited by IP, involved the issue of early retirement and severance costs resulting from a change in company ownership. (Staff Ex. 19.0, p. 9) (Staff Init. Br., pp. 29-32)

Staff argues that the costs in question here are transaction costs as evidenced by the proximity in time between the merger, the assumption of activities by Dynegy and the employee terminations. Staff also states that IP's treatment of these costs within its own organization is inconsistent, as it has requested only electric delivery services customers, but not gas customers, to pay for them. (Staff Ex. 19.0, p. 11; Staff Ex. 1.0, pp. 17-18, citing Docket No. 99-0419) Staff also notes that some of the severance costs may have been incurred in connection with a broad restructuring of IP's activities including divestiture of its electric generation business and cessation of its retail energy marketing activities. However, Staff states that any severance costs related to these non-delivery services activities should not be reflected in the revenue requirement, because they are not related to electric distribution. (Staff Ex. 19, p. 10) (Staff Init. Br., pp. 30-31)

Staff also argues that even though IP actually incurred the severance expenses in the test year, it is not automatically entitled to rate recovery, because Section 16-108 (a) of the PUA allows for recovery of costs of providing delivery services, not simply recovery of all amounts spent by the utility. Staff argues that if rate recovery is allowed, ratepayers will receive a reduced benefit from the effect of the permanent wage reductions that are also reflected in the revenue requirement. (Staff Ex. 19.0) Further, IP will not continue to incur severance costs on an on-going basis, because the cause of these particular severance costs, i.e., the merger, is a one-time event which does not continue prospectively into the future. (Staff Init. Br., pp. 31-32)

(3) CUB/AG's Position

CUB/AG witness Effron did not oppose recovery of the 2000 severance and early retirement costs over a five-year amortization period; however, in their Initial Brief, CUB/AG state that they agree with Staff's position. CUB/AG also argue that the Commission should treat the amortization period as having commenced in 2000. CUB/AG state that this would be consistent with the fact that IP began to realize the savings from the employee reduction in 2000. CUB/AG indicate that the five-year amortization period should be 2000 through 2004. (CUB/AG Init. Br., pp. 15-16)

(4) Commission's Analysis and Conclusion

Based on its review of the record and of the arguments of the parties, the Commission is of the opinion that IP should be allowed to amortize the severance and early retirement costs over a 5 year period and to include the jurisdictional portion of the annual amortization expense in its distribution operating expenses for purposes of this case. The Commission concludes that recovery of these costs through distribution rates is justified by the substantial savings produced by the severance and early retirement programs. The Commission acknowledges that in certain recent merger cases, as cited by Staff, the Commission has indicated that employee termination costs are part of merger transaction costs that should not be recovered from customers. In this case, the Commission finds the facts to be different, and recovery to be warranted, because it is clear that the severance and early retirement costs were incurred to produce savings in operating costs that are being passed on to ratepayers directly in this case, and in amounts far in excess of the amounts of severance and early retirement costs that IP is seeking to include in the annual distribution revenue requirement. Further, the record does not support Staff's contention that these costs were incurred to produce an ownership change. In any event, as the Commission stated in GTE Corporation and Bell Atlantic Corporation, Docket 98-0866 (Oct. 29, 1999), "To the extent that costs are incurred to produce savings and are shown to be both reasonable and directly related, netting is appropriate. As a matter of logic, the only savings that can be realized are net savings." (Id., p. 41) In addition, the Commission rejects CUB/AG's proposal to deem the 5-year amortization period to have started in 2000. Such an approach would result in under-recovery of costs that the Commission has concluded are legitimate and recoverable.

c. Amortization of expense for statutory rulemakings

(1) IP's Position

In the 1999 DST Case, the Commission allowed IP to recover costs for outside services incurred in connection with two rulemaking proceedings before the Commission that were required by the Electric Service Customer Choice and Rate Relief Law of 1997. These proceedings were the "affiliate transactions" rulemaking (Dockets 98-0013 & 98-0035 Cons.) and the "code of conduct/functional separation" rulemaking (Dockets 98-0147 & 98-0148 Cons.). The former was required by §16-121 of the PUA (220 ILCS 5/16-121) while the latter was required by §16-119A (220 ILCS 5/16-119A). In the 1999 DST Case, the Commission allowed IP to recover certain costs of these proceedings that had been incurred in 1998 and 1999, with the costs to be amortized and recovered over a five-year period. (See IP Ex. 1.1, pp. 19-20, and IP Exs. 1.19-1.20) In this case, IP has included in the revenue requirement the portions of the costs of the two rulemakings allowed in the 1999 DST Case that have not yet been amortized and recovered. IP has also included additional costs incurred in the two proceedings that were not known at the time of the 1999 DST Case. IP proposes to amortize the entire amount over a five-year period, consistent with the treatment in the 1999 DST Case. (IP Ex. 1.1, pp. 19-20; IP Ex. 1.19-1.20) (IP Init. Br., pp. 57-58)

IP notes that Staff witness Hathhorn accepted the recovery of the remaining portion of the expenses for the rulemaking proceedings that were allowed to be recovered in the 1999 DST Case, but she objected to recovery of the additional costs for the rulemakings that were incurred after the 1999 DST Case, characterizing the latter costs as "out of period costs", i.e., incurred in 1999, and asserting that allowing recovery would create a mismatch between current period operating expenses and current period revenues. IP argues that Ms. Hathhorn's arguments are misplaced and do not justify disallowance of the remainder of the costs IP incurred for the two statutorily-required rulemakings. First, IP notes, the expenses for these proceedings that the Commission allowed to be recovered in the 1999 DST Case were not incurred in the test year in that case, 1997, because the two rulemaking dockets were not initiated by the Commission until 1998. The expenses for the rulemakings that were allowed in the 1999 DST Case were incurred in 1998 and 1999. (IP Ex. 1.34, p. 33; IP Ex. 1.63, p. 26) Second, IP states that the costs were non-recurring costs that IP was required to incur in connection with statutorily-required proceedings. IP contends that the Commission determined in the 1999 DST Case that the Company should be allowed to recover its costs of participating in these two rulemakings. IP disagrees with Ms. Hathhorn's characterization that it is now seeking to recover costs that were under-budgeted or unanticipated at the time of the 1999 DST Case. IP states that at the time of the 1999 DST Case, the two rulemakings were ongoing, and IP fully anticipated incurring additional costs. However, IP argues, because the remaining costs had not yet been incurred, they were not known with sufficient certainty to be included in setting rates in the 1999 DST Case. Thus, IP concludes, the additional costs have now been incurred and are known, so IP should be allowed to recover them, over a five-year amortization period, consistent with the determination in the 1999 DST Case that recovery of the costs of these statutorily-mandated rulemakings should be allowed. (IP Ex. 1.34, pp. 33-34; IP Ex. 1.63, p. 26) (IP Init. Br., pp. 58-59)

(2) Staff's Position

Staff proposes to disallow $20,000 of 1999 outside services employed costs, incurred outside of the test year, relating to the Standards of Conduct/Functional Separation and Affiliate Transactions rulemakings. Staff states that these costs were not included in the amortization amounts allowed by the Commission in the 1999 DST Case. (Staff Ex. 1.0, pp. 7-8) (Staff Init. Br., p. 25)

Staff contends that IP's proposal to include these costs is based upon its erroneous belief that the 1999 DST Order included approval of all future rulemaking costs. (IP Ex. 1.34, p. 34) Staff believes the Commission did not approve such costs in its prior order. Rather, Staff argues, the Commission simply allowed the test year expenses and known and measurable adjustments associated with those rulemakings to be amortized for the test year. The Commission treated these expenses the same as any other operating expense. (Staff Ex. 19.0, p. 6) Staff states that the prior DST case amount was determined based on the historical test year costs plus the known and measurable pro forma amounts at the time, for that case, amortized over five years. Similarly, Staff argues, the revenue requirement in this case should be based on the current test year and its pro forma adjustments, allowing for any unamortized balances approved in the prior DST case. Staff is unaware of any Commission order allowing a utility to update its unamortized balance from a previous case for additional costs. (Staff Ex. 1.0, pp. 9-10) (Staff Init. Br., pp. 25-26)

Staff claims that the effect of including additional, incremental 1999 costs in the 2000 test year would be to mismatch current period operating expenses with current period revenues. Additionally, Staff believes that IP's adjustment results in an overstatement of the balance of Account 923 by the adjustment for the 1999 amount, since the revenue requirement already reflects a normal, on-going level of such expense at the year 2000 level. Staff states IP's proposal selects isolated expenses related to the 1999 DST Case and improperly attempts to make 1999 costs appear to be test year costs. (Staff Ex. 1.0, p. 8) (Staff Init. Br., p. 26)

Staff does not believe that IP has presented sufficient evidence to support making an exception to test year rules. Staff states that IP's current adjustment relates to unique costs from pro forma adjustments in the 1999 DST Case. Further, Staff states that IP did not analyze if all the other expenses and pro formas from that case actually were incurred at the level approved in its revenue requirement. Staff believes that such action would be retroactive ratemaking. Staff states that the actual costs of IP's prior pro forma adjustments may have been higher or lower than the amounts approved in the 1999 DST Case; regardless, Staff argues that it is most certain that the exact amount approved was not IP's actual experience. Staff asserts that the Commission's past practice has been to accept such imperfection of the process while adhering to established test year rules. Thus, Staff concludes, since IP chose to use a 12/31/2000 historical test year, with known and measurable changes through 6/30/2002, its adjustment for 1999 costs is inappropriate. (Staff Init. Br., pp. 26-27)

Staff asserts that the Commission has previously considered the issue of allowing operating expenses from a past period into another period's revenue requirement and determined it is inappropriate. In Docket No. 98-0895, Staff notes, the Commission rejected Citizens Utilities Company of Illinois, d/b/a Citizens Water Resources' ("CUCI") application for an order approving deferred accounting for Year 2000 ("Y2K") compliance costs since such costs were operating expenses that would fall outside the test year period. (Docket No. 98-0895, Order, p. 4, March 15, 2000). Staff claims that, although the expenses at issue appear to be reasonable and made in the public interest, they are not sufficiently large, or sufficiently unique, to justify special accounting treatment. Rather, Staff contends, the requested deferral would improperly match expenses from a non-test year with revenues from a test year. Thus, Staff believes that IP's requested deferral is contrary to the ratemaking principle that expenses be recognized in the year in which they are incurred. Staff asserts that IP's request for additional 1999 rulemaking expenses has little substantive difference from the CUCI case discussed above. Thus, Staff concludes, the Commission has already analyzed a request such as IP is proposing with respect to the rulemaking expenses in question and found such action inappropriate. (Staff Ex. 1.0, pp. 10-11) (Staff Init. Br., pp. 48-49)

(3) Commission's Analysis and Conclusion

The Commission concludes that Staff's proposed adjustment should be rejected and that IP should be allowed to amortize and recover the remaining expenses for the two statutorily-required rulemaking proceedings that were incurred in 1999 but were not known at the time of the 1999 DST Case. These expenses are distinguishable from the more normal scenario in which a utility projects or anticipates a level of expenses in a rate case and the actual results diverge from the expected expenses that were built into the revenue requirement in the prior case. Here, the Commission believes that IP should be allowed the opportunity for full recovery of its outside services expenses incurred in connection with the participation in the two statutorily-required rulemaking proceedings. The Commission notes that Staff acknowledges that the expenses in question are reasonable and made in the public interest.

d. Amortization of Y2K expenses

(1) IP's Position

In the 1999 DST Case, the Commission allowed IP to recover $2,025,000 of expenses for compliance with Year 2000 ("Y2K") requirements, with the costs to be amortized and recovered over a six-year period. In this case, IP seeks recovery of the jurisdictional portion of the unamortized balance of the Y2K expenses allowed in the 1999 DST Case, plus an additional $600,000 of Y2K expenses that were incurred in 1999 and 2000. IP states that the additional costs would also be amortized and recovered over a six-year period. (IP Ex. 1.1, p. 20; IP Ex. 1.21; IP Ex. 1.34, pp. 34-35; Rev. IP Ex. 3.24, p. 2, col. (15)) (IP Init. Br., p. 59)

IP disputes Staff witness Hathhorn's proposal to deny recovery of the additional Y2K costs incurred in 1999. IP states that Ms. Hathhorn's rationale for disallowing these costs was essentially the same as her rationale for disallowing the additional costs of the statutorily-mandated rulemaking proceedings, namely, that they are "out of period" costs. (Staff Ex. 1.0, pp. 13-14) IP argues that Ms. Hathhorn's proposed disallowance should be rejected for reasons similar to those with respect to the additional costs for the two rulemakings. Specifically, the Commission in the 1999 DST Case allowed recovery of non-recurring costs incurred in order to address potential Y2K issues. IP asserts that it should now be allowed to recover those Y2K compliance costs that could not be identified at the time of the 1999 DST Case. (IP Ex. 1.34, p. 35; IP Ex. 1.63, p. 26) (IP Init. Br., pp. 59-60)

(2) Staff's Position

Staff witness Hathhorn proposed to disallow the portion of the Y2K amortization expense requested by IP that represented additional 1999 costs, as out of period costs. (Staff Ex. 1.0, pp. 11-12) This adjustment would result in a $34,000 disallowance. (Staff Ex. 19.0, Sched. 19.7) Staff asserts that this issue is based upon the same theory as that of the 1999 rulemaking amortization expense adjustment. In summary, Staff finds no reason to treat the Y2K expenses any different than other operating expenses of the Company. (Staff Ex. 19.0, p. 7) (Staff Init. Br., pp. 28-29)

(3) Commission's Analysis and Conclusion

The Commission concludes that Staff's proposed adjustment should be rejected and that IP should be allowed to amortize and recover the remaining expenses for Y2K compliance activities that were incurred in 1999 but were not known at the time of the 1999 DST Case. These expenses are distinguishable from the more normal scenario in which a utility projects or anticipates a level of expenses in a rate case and the actual results diverge from the expected expenses that were built into the revenue requirement in the prior case. Here, the Commission believes that IP should be allowed the opportunity for full recovery of its outside services expenses incurred in connection with readiness to handle potential Y2K problems without any service disruptions occurring.

e. Allocation of administrative and general expenses to Distribution, and billings for services from Dynegy

(1) IP's Position

IP states that it determined the amount of its A&G expenses to be included in distribution operating expenses in a similar manner to the way it determined the amount of G&I plant to be included in rate base, using labor expense allocation factors as the Commission had directed in the 1999 DST Case. (IP Ex. 1.1, pp. 16-17; IP Ex. 1.4; IP Ex. 1.34, pp. 5, 55-56) IP started with total electric A&G expense as reported in its FERC Form 1 for 2000, and allocated a portion of the total electric A&G expense to electric distribution using a transmission and distribution labor expense allocator. No party noted any errors in IP's calculation of the labor expense allocation factors. (IP Ex. 1.1, pp. 16-17; IP Ex. 1.34, pp. 55-56; IP Ex. 1.63, pp. 7-8) IP notes that A&G expenses include the costs associated with such functions as accounting, regulatory, legal, human resources, public affairs, executive officers and administrative staff, as well as costs associated with office supplies and expenses, outside services, property insurance and claims, pensions and benefits, and miscellaneous expenses. (IP Ex. 1.34, p. 47) IP states that like G&I plant, A&G expenses support all of a utility's businesses; it is in the nature of these joint and common costs that they are needed to support a single line of business, but can also support additional lines of business without significant increase. (IP Ex. 1.34, p. 5) (IP Init. Br., pp. 60-61)

IP asserts that Staff's, IIEC's and CUB/AG's proposed adjustments to A&G expenses are without merit. IP notes that Staff witness Lazare and IIEC witness Phillips each took issue with the amount of A&G expense that IP included in distribution operating expense using the labor allocation procedure; both contended that IP's use of the labor allocator produced a large increase in the amount of A&G expense included in distribution operating expense as compared to the amount of A&G expense included in distribution operating expense in the 1999 DST Case. IP states that whereas during the 1997 test year used in the 1999 DST Case IP owned generating stations, had a generation business function and had generation employees whose labor expense was included in the denominator of the labor expense allocation factor, in the 2000 test year used in this case, IP owned essentially no generation, had essentially no generation labor expense, and therefore did not include any generation labor expense in the development of its labor expense allocation ratios for A&G expense. (IP Ex. 1.34, pp. 55-56) IP contends that Staff's and IIEC's proposed limitations on the amount of A&G expenses to be included in distribution operating expense in this case are arbitrary and should be rejected, just like their proposed limitations on the amount of G&I plant in distribution rate base should be rejected. IP argues that it properly determined the amount of its A&G expense that should be included in distribution operating expense using a labor expense allocator as prescribed by the Commission in the 1999 DST Case. IP contends that Staff's and IIEC's proposed adjustments were not based on any sort of detailed review of IP's overall A&G expenses or on identification of any A&G expenses that were imprudently incurred or are unnecessary to provide service. IP states that Staff witness Lazare failed to perform or review any studies or analyses of IP's test year A&G expenses to identify any specific items of A&G expense that should not be included in the revenue requirement, and also failed to perform or review any studies or analyses to identify the types or categories of A&G expenses that IP incurred in the test year. (Tr. 780-81) IP notes that, in contrast, Staff Accounting witnesses Hathhorn and Pearce conducted a thorough review of the operating income statement proposed by the Company, and proposed numerous specific adjustments to IP's proposed operating expenses, including specific disallowances and other adjustments to A&G expenses. (Tr. 283-86, 288-89) IP states that like their proposed adjustments to G&I plant, Staff's and IIEC's adjustments to A&G expense are grounded in an erroneous premise that the Commission, in the 1999 DST Case, determined a fixed and immutable relationship between the amount of direct O&M expense and the amount of A&G expense needed to provide distribution service, which should be carried forward in all future cases. (IP Ex. 1.63, pp. 8-9) IP contends that there is no basis for such a premise, or for the arbitrary limitations Staff and IIEC would impose on the amount of IP's A&G expense to be included in distribution operating expense. IP states that the conceptual flaws in Staff's and IIEC's proposed adjustments to G&I plant are equally applicable to their proposed adjustments to A&G expense. (IP Init. Br., pp. 61-64)

With respect to Staff's arguments based on statements made by IP witness Dreyer in Docket 99-0209 concerning the transfer of IP's fossil generating units, IP reiterates the response it gave in connection with the G&I plant issue. IP also notes that DMG ceased to rely on IP for the provision of significant levels of overhead, administrative and support services after the closing of the Illinova-Dynegy merger because it thereafter obtained those services from its corporate parent, Dynegy. IP reiterates that in 2000, IP properly billed both DMG and AmerGen (the buyer of IP's nuclear generating station) for those services that IP provided to each company, and that the revenues from and costs of providing these services were accounted for in a manner that removes the revenues and costs from the determination of the revenue requirement in this case. IP states that Mr. Lazare did not dispute these facts. (See IP Ex.1.34, pp. 56-61, and IP Exs. 1.56-1.57; Tr. 768-777) (IP Init. Br., p. 64)

IP contends that in addition to the adjustments proposed by Staff and IIEC, CUB/AG propose a different, but similarly unsupported, adjustment to the A&G expenses included in distribution operating expenses. IP notes that CUB/AG witness Effron focused solely on the increase in one A&G account, Account 923, Outside Services Employed, from 1997 (the test year in the 1999 DST Case) to 2000. Within that account, he focused solely on the charges to IP for services provided in 2000 by its corporate parent, Dynegy (charges which, of course, did not exist in 1997). Without giving any consideration to decreases in other accounts that IP has been able to achieve as a result of functions that IP formerly performed internally being transferred to Dynegy after the merger, Mr. Effron recommended that all charges from Dynegy be disallowed. (GCI Ex. 2.0, pp. 11-14) IP points out that it responded to this recommendation with a detailed itemization and explanation of the services provided by Dynegy and the related charges, and also identified reductions in internal costs that it had achieved as a result of the transfer of functions to Dynegy. IP contends that Mr. Effron, without responding to the specifics of IP's presentation, simply continued to recommend that all charges from Dynegy be disallowed. (GCI Ex. 4.0, p. 10) Thus, IP concludes, Mr. Effron's proposed adjustment is arbitrary and not based on any specifics of the A&G costs in question, and should be rejected. IP contrasts CUB/AG witness Effron's approach with that of Staff witness Ms. Hathhorn, who did review the Dynegy billings to IP for the test year, and in fact identified an error, which IP accepted as an adjustment in this case, thereby reducing operating expense by $1,035,000. (Rev. IP Ex. 3.24, p. 3, col. (30)) IP notes that Ms. Hathhorn did not identify any other errors in the Dynegy billings to IP. (Tr. 289) (IP Init. Br., pp. 64-65)

IP maintains that its electric A&G Expenses are reasonable. In response to Mr. Lazare's and Mr. Phillips' proposals, IP presented an analysis of the change in its electric A&G expenses from 1997, the test year in the 1999 DST Case, to 2000, the test year in this case. IP showed that the total annual unadjusted electric A&G expenses (<u>i.e.</u>, including any non-recurring expenses and before consideration of any ratemaking adjustments), decreased approximately 3% from 1997 to 2000, from $73.6 million to $71.6 million. IP notes that total electric A&G expenses had increased by 17.9% from 1997 to 1999, but then decreased by 17.4% from 1999 (the year in which IP's generation assets were sold) to 2000. (IP Ex. 1.34, p. 48; IP Ex. 1.51) (IP Init. Br., p. 65)

IP states that from 1997 to 2000, three A&G accounts showed increases: Account 920, Administrative and General Salaries ($5.3 million increase); Account 923, Outside Services ($25.2 million increase); and Account 925, Injuries and Damages ($7.1 million increase). (IP Ex. 1.34, p. 48) However, IP explains, the 2000 total in Account 920 included $13 million of one-time severance payments. IP has proposed to remove the severance payments from test year expenses and amortize them over five years. IP states that excluding the $13 million of severance costs recorded in 2000, A&G salaries (Account 920) fell by about $7.7 million, or 38%, from 1997 to 2000. Further, IP notes that, the 2000 total in Account 920 does not fully reflect the impacts of IP's headcount reductions in 2000, because it includes compensation paid to terminated employees in 2000 before their departure. IP has also proposed to remove these amounts from test year expenses for ratemaking purposes. (IP Ex. 1.34, p. 49) IP states that it reduced its overall headcount in A&G positions by 155 employees from year-end 1997 to year-end 2000 (443 employees to 288 employees). IP notes that the number of A&G employees had increased to 461 at year-end 1999, so the decrease in A&G headcount in 2000 was actually 173 employees. IP also notes that the headcount in the T&D functions was reduced from 1,880 employees at year-end 1997 to 1,749 employees at year-end 2000, and in fact was reduced by 196 employees (from 1,945 at year-end 1999 to 1,749 at year-end 2000) during 2000. (IP Ex. 1.34, p. 50; IP Ex. 1.52) IP states that the annualized savings due to the elimination of 297 employees in 2000 is $25,501,515, of which $14,765,377 is the jurisdictional electric distribution portion. (IP Ex. 1.63, p. 27; IP Ex. 1.70) (IP Init. Br., pp. 65-66)

IP states that the $7.1 million increase in expenses recorded in Account 925, Injuries and Damages, from 1997 to 2000 was primarily due to recording a $5.5 million accrual in 2000 for three pending litigation claims. As discussed elsewhere in this Order, IP has removed this $5.5 million accrual from test year expenses and will amortize it over three years. (IP Ex. 1.34, p. 54) (IP Init. Br., pp. 66-67)

IP states that the $25.2 million increase in Account 923 from 1997 to 2000 is primarily attributable to the billings to IP associated with services now provided by Dynegy. This increase also includes an expense for a portion of bonuses paid to Dynegy executives that was allocated to IP, but which has been removed in its entirety for ratemaking purposes. (IP Ex. 1.30) Excluding the expense for these bonuses, the 2000 expense for Account 923 was approximately $16.3 million higher in 2000 than in 1997. (IP Ex. 1.34, p. 52) (IP Init. Br., p. 67)

IP witness Carter detailed the nature of the billings from Dynegy included in Account 923 for 2000, the nature of the services provided by Dynegy, and the reductions in IP's work force that have been made possible by the transfer of functions to Dynegy. (IP Ex. 1.34, pp. 50-53; IP Exs. 1.52-1.55) IP states that services provided by Dynegy fall into seven principal areas: (1) President/CEO/COO; (2) financial; (3) legal; (4) human resources; (5) information technology ("IT"); (6) communications; and (7) administration. The functions performed by Dynegy in these seven areas include serving as IP's Chairman, Chief Executive Officer, Chief Financial Officer, Treasurer, Assistant Treasurer and Vice President - Tax; managing IP's commercial paper program, debt financings and relationships with rating agencies, banks and the financial community; preparation of IP's federal and State tax filings and estimated and final tax payments; review of IP's SEC filings and financial statements and legal support for SEC filings; overseeing the insurance and risk management functions, negotiation of IP's insurance premiums and maintenance of relationships with insurance carriers; performance of internal audits for IP; performance of the corporate secretary function, including maintenance of corporate records; leadership and direction for human resources programs and functions; and leadership and direction for IT functions, including monitoring infrastructure and monitoring and maintaining electronic storage, server support, applications development, IT contract administration, and development and maintenance of specific IT functions. IP states that in a number of the functional areas in which services are now provided to IP by Dynegy, IP has been able to achieve significant headcount reductions. IP cites these examples: (1) Dynegy now provides the internal audit function for IP; therefore, IP's Audit and Compliance Services group (12 employees in 1997) was eliminated in 2000. (2) IP's shareholder services function was eliminated from its Legal Services Department; the head count in Legal Services dropped from 24 in 1997 to 12 in 2000. (3) IP's Human Resources group has been reduced from 53 persons in 1997 to 25 persons in 2000. (4) With many of IP's accounting, financial planning and management and treasury functions now performed by Dynegy, IP's Financial Business Group has been reduced from 80 persons in 1997 to 36 persons in 2000. (5) With IT functions now being directed by Dynegy, IP's head count in IT has dropped by 46 employees from 1997 to 2000. (IP Ex. 1.34, pp. 50-51; IP Ex. 1.52) (IP Init. Br., pp. 67-68)

IP states that the costs for the services and functions performed by Dynegy are billed to IP in accordance with the SFA approved by the Commission in Docket 99-0114. (IP Ex. 1.34, p. 53) IP notes that Staff witness Hathhorn reviewed the test year billings from Dynegy to IP and found one error, which IP has accepted as an adjustment. IP states that no other witness identified any errors or non-compliances in Dynegy's billings for services pursuant to the SFA. IP notes that Staff witness Lazare testified that he was not contending that IP had not been billed correctly for services provided by Dynegy under the SFA. (Tr. 770-71) (IP Init. Br., pp. 68)

IP states that when adjustments are made for non-recurring costs and other ratemaking adjustments, the data show that IP achieved significant reductions in its ongoing level of electric A&G expenses from 1997 to 2000. IP notes that the total electric A&G expenses in 1997 were $73.6 million; there were no significant non-recurring expenses that were removed from this test year amount for ratemaking purposes in the 1997 DST Case. The total electric A&G expenses in 2000 were $71.6 million; however, $37.2 million of this amount is non-recurring expenses or one-time adjustments; with these removed, the ongoing level of electric A&G expenses is $34.5 million, which is a 53.2% reduction from 1997. (IP Ex. 1.63, p. 35; IP Ex. 1.72) (IP Init. Br., p. 69)

In response to Staff's argument that anticipated savings from the Illinova-Dynegy merger have not been realized, IP contends that it has not failed to pass merger savings on to delivery services customers, and that Staff's assertions are baseless. IP points out that Staff witness Lazare cited statements made at the time of the merger announcement that the combined companies expected annual pre-tax revenue enhancements and cost savings of $125 - $165 million, with about one-third of this amount attributable to anticipated cost savings. (Staff Ex. 5.0, pp. 13-14) However, Mr. Lazare acknowledged that contemporaneous statements put the anticipated cost savings at $59 million, and that the figures for anticipated revenue enhancements and cost savings were anticipated results for the entire, combined post-merger organization, not just for IP. (Tr. 777-78) Therefore, only a portion of these savings would be attributable or allocable to IP's electric distribution business. (IP Ex. 1.34, pp. 53-54) IP contends that in any event, the record shows that substantial savings have been achieved since the merger: (1) IP eliminated 297 employees in 2000, almost entirely as a result of the merger, resulting in annualized total Company savings of $25.5 million and savings to the electric distribution business of $14.8 million. (IP Ex. 1.63, p. 27; IP Ex. 1.70) (2) IP's total electric A&G expenses fell by $15.1 million from 1999 to 2000. (IP Ex. 1.34, p. 54; IP Ex. 1.51) (3) IP's total headcount in transmission, distribution and A&G functions was reduced by 369 employees from year-end 1999 to year-end 2000. (4) In Docket 99-0419, in which the Commission approved the gas utility aspects of the merger, IP indicated an anticipated 5% reduction in the combined 6,500 person workforce of Illinova and Dynegy, i.e., a 325 employee reduction; in fact, IP's headcount alone was reduced by 369 from year-end 1999 to year-end 2000. (IP Ex. 1.34, p. 54) (IP Ex. 1.34, p. 54; IP Ex. 1.52) IP concludes that it has both realized merger-related cost savings and is reflecting those savings in its proposed revenue requirement in this case. (IP Init. Br., pp. 69-70)

IP concludes that Staff, IIEC and CUB/AG have ignored the nature of common costs, and base their proposed A&G adjustments on an invalid assumption that the Commission has established a fixed and immutable relationship between direct O&M expense and A&G expense in the distribution revenue requirement that must be adhered to. IP states that its electric A&G expenses have actually decreased since 1997, the test year in the 1999 DST Case, and since 1999, when IP divested its generation assets and business and the Illinova-Dynegy merger was announced. IP states that the other parties' adjustments are not based on any analysis of the specific A&G expenses incurred by IP in 2000 or on any identification of specific A&G expense items that are imprudent or unnecessary, and that the other parties have not refuted IP's detailed explanation of its test year A&G expenses, including the billings for services and functions now performed by Dynegy. IP concludes that the A&G expenses it has included in the distribution revenue requirement are reasonable and necessary to support the distribution business and should be allowed for ratemaking purposes. (IP Init. Br., p. 71)

(2) Staff's Position

Staff's arguments concerning the amount of A&G expense to be included in distribution operating expense in this case were presented in the sections of its briefs on G&I plant, and are summarized in the section of this Order on G&I plant in rate base, above.

(3) IIEC's Position

IIEC's arguments concerning the amount of A&G expense to be included in distribution operating expense in this case were presented in the sections of its briefs on G&I plant, and are summarized in the section of this Order on G&I plant in rate base, above. (IIEC Init. Br., p. 3, n.3)

(4) CUB/AG's Position

CUB/AG notes that the Dynegy consolidated group, which includes IP, began operating under a SFA, pursuant to which services such as financial, legal, information technology, and human resources are exchanged between IP and other Dynegy affiliates. In its 2000 FERC Form, IP states that management believes that the amounts charged to IP under the agreement are "similar to costs that IP would have incurred for these services on a stand alone basis." In the 1999 DST Case, the Commission approved the inclusion of $15,938,000 of A&G expense in the delivery services revenue requirement. The $41,682,000 IP is now proposing to include is an increase of approximately 162%. CUB/AG assert that an increase of this magnitude is excessive. According to CUB/AG, it is possible that the divestiture of IP's generating units would cause an increase in A&G expense being functionalized to delivery services, as a result of some loss of economies of scale. (GCI Ex. 2.0, p. 12) However, even allowing for some loss of such economies, CUB/AG maintain an increase of 162% is still excessive, especially since the fossil generating units were divested to an affiliate and should still absorb the same relative proportion of A&G expenses as if the facilities were still owned by IP. (GCI Ex. 2.0, p. 13) CUB/AG maintain that IP has not justified this increase. CUB/AG therefore propose to eliminate all charges from Dynegy from the A&G component, which would reduce the A&G expense to $23,937,000. (GCI Ex. 4.0, p. 10) (CUB/AG Init. Br., pp. 17-18)

(5) Commission's Analysis and Conclusion

The Commission concludes that the procedure employed by IP to determine the amount of its A&G expenses that should be included in distribution operating expenses is appropriate and consistent with the procedure that the Commission determined should be used in the 1999 DST Case, i.e., based on the ratio of distribution labor expense for the test year to IP's total direct electric expense for the test year, 2000. The Commission notes that no party raised any issues with respect to IP's allocation of A&G expense between the electric and gas utilities or with respect to IP's calculation of the distribution labor expense ratios. The Commission concludes that the amount of A&G expense that should be included in distribution rate base for purposes of this case is the amount proposed by IP, as adjusted based on any specific adjustments to A&G expense that are adopted by the Commission in other sections of this Order.

The Commission does not accept Staff's contention that based on the 1999 DST Order, IP should be required to allocate a portion of it's A&G expense to "generation" even though prior to the test year in this case IP divested all of its generation, and had essentially no generation facilities, business or labor expense during the 2000 test year. The Commission also does not accept the arguments of Staff and IIEC that based on the 1999 DST Order, the mathematical relationships between A&G expenses in distribution operating expenses and distribution labor expense must be maintained in this case. The Commission recognizes that it is in the nature of common costs such as A&G expenses that support multiple lines of business, that the fact that one line of business and its direct assets is divested, does not mean that the amount of A&G expense can be reduced correspondingly. IP has sold its generation assets and exited the generation business, as permitted by the PUA, with this Commission's approval, and therefore IP cannot be required to continue to allocate a portion of it's A&G expenses to "generation" for purposes of setting its distribution rates. The Commission also does not accept the arguments to the contrary made by Staff based on testimony from Docket 99-0209, the comparison to the current Ameren delivery services case, the estimates of cost savings from the Illinova-Dynegy merger, or so-called "least-cost ratemaking." In this regard, the Commission concludes that IP has shown that it has realized cost savings as a result of the Illinova-Dynegy merger, which are being reflected in the revenue requirement in this case.

It is, of course, an appropriate inquiry as to whether, to the extent that IP is providing services and facilities to the new owners of its generating facilities, IP is being properly compensated for those services and facilities. In this case, IP detailed its billings to DMG and AmerGen in the test year for services and facilities it provided to those companies, and showed that it was compensated based on fully-distributed costs, and that both the revenues received and the costs of the services were accounted for in such a manner that they do not affect the distribution revenue requirement in this proceeding. No party took issue with this showing.

The Commission notes that Staff, IIEC and CUB/AG raised a legitimate issue when they called into question the increase in A&G expense that IP is proposing for inclusion in distribution operating expenses in this case as compared to the amount of A&G expense allowed in the 1999 DST Case. However, IP demonstrated in response that it has achieved substantial reductions in its electric A&G expenses from 1997 to 2000, as well as from 1999, when it sold its fossil and nuclear generating stations, to 2000. In response to IP's evidence, no other party attempted to show that any items of IP's G&I plant in service are excessive, imprudent or unnecessary to support its distribution business, other than CUB/AG's general proposal (discussed in the next paragraph) that all charges for A&G services from Dynegy should be excluded (and except as reflected in other specific adjustments that are discussed in other sections of this Order).

The Commission also declines to accept CUB/AG's proposal that all charges from Dynegy in the test year should be disallowed. Similar to the analysis of overall A&G expenses described in the preceding paragraph, while it was appropriate for CUB/AG to call into question the amount of billings from Dynegy included in test year expenses, IP then responded with a detailed explanation of the billings from Dynegy and the services they covered, as well as indicating numerous areas in which IP has been able to achieve workforce reductions and other internal cost savings because services and functions are now provided by Dynegy. Further, except for the one error identified by Staff witness Hathhorn which IP has accepted, the record demonstrates that IP's charges from Dynegy for A&G services and functions were in compliance with the provisions of the SFA approved by this Commission. In response to IP's detailed explanation relating to the charges from Dynegy, CUB/AG failed to identify any specific charges from Dynegy that were excessive, imprudent or unnecessary to support the distribution business, or not in compliance with the SFA.

For these reasons, the Commission accepts IP's proposed amount of A&G expense as appropriate for inclusion in distribution operating expenses in this case (again, as adjusted based on other, specific adjustments as discussed elsewhere in this Order).

f. Amortization of accrual for injuries and damages expenses

(1) IP's Position

During the test year, IP recorded a $5.5 million accrual for liability exposure for injuries and damages expense in connection with three pending or potential litigation claims. (IP Ex. 1.34, p. 66) IP submits that creation of this accrual was consistent with Statement of Financial Accounting Standards No. 5, Accounting for Contingencies ("SFAS 5"). SFAS 5 states that an estimated loss for a loss contingency should be charged to expense, and a liability recorded, if both of the following conditions are met: (1) information available prior to the issuance of the financial statements indicates that it is probable that a liability has been incurred at the date of the financial statements, and (2) the amount of the loss can be reasonably estimated. IP recognized an expense for these three claims in December 2000 because it was probable that a liability had been incurred and IP could reasonably estimate the loss. (Id.; IP Ex. 1.63, p. 40) (IP Init. Br., pp. 71-72)

Initially, IP proposed to include the jurisdictional portion of the $5.5 million amount in test year expenses as a legitimate and necessary operating expense. However, in response to questions raised by CUB/AG witness Effron about the resulting test year level of Injuries and Damages expense in relation to the levels incurred in recent years (see GCI Ex. 2.0, pp. 8-10), IP proposed to amortize the $5.5 million accrual over a three-year period. IP states that the three-year amortization period is based on two factors: (1) The DST rates established in this case are expected to be in effect for approximately three years (early 2002 until early 2005); therefore, the expense would be fully amortized by the time new DST rates are established; and (2) litigation matters such as those for which the accrual was established can take two to five years to be brought to resolution. (IP Ex. 1.34, p. 67) IP states that removing the accrual expense from test year expenses and amortizing the amount over a three-year period results in a net reduction to operating expenses of $3,225,000. (Id.; IP Ex. 1.60) (IP Init. Br., p. 72)

IP contends that CUB/AG's objection to any recovery of this expense, which is based on the argument that IP should not be allowed to include both actual claims paid and accruals for future claims payments in the test year, ignores the relevant accounting requirements, and should be rejected. IP disputes CUB/AG's argument that allowing recovery of both actual claims payments and SFAS 5 accruals is "double recovery." IP characterizes Mr. Effron's argument that IP should not be allowed to include both actual claims paid and accruals for future payments as a red herring because, according to IP, both the current period payments and the accrual are current period expenses. IP explains that SFAS 5 requires the recording of a current period expense when it is probable that a liability has been incurred and the amount of the loss can be reasonably estimated. IP asserts that Mr. Effron essentially agreed that the recording of an expense is required by Generally Accepted Accounting Principles under such circumstances, and he did not take issue with IP's determination that this particular expense and accrual should be recorded in 2000. (See Tr. 414-19) Since the $5.5 million accrual is a current period (test year) expense, IP argues, it is appropriately recognized in setting rates. (IP Init. Br., pp. 72-73)

IP acknowledges that recording the expense for the $5.5 million accrual resulted in an unusually high total level of Injuries and Damages expense in 2000 as compared to prior years; IP states that it appropriately addressed this fact by agreeing to amortize the $5.5 million accrual over three years. (IP Ex. 1.63, p. 40) IP concludes that CUB/AG's proposal to completely exclude the $5.5 million accrual from the revenue requirement in this proceeding is unsupported. (IP Init. Br., p. 73)

(2) CUB/AG's Position

CUB/AG assert that the injuries and damages expense proposed by IP should be reduced. CUB/AG contend that IP's proposed injuries and damages expense component for the test year is considerably higher than the injuries and damages charged to Account 925 in the past. CUB/AG contend that this proposed injuries and damages expense includes both actual claims paid and an accrual for future claims, including a $5.5 million accrual as a reserve for potential claims that IP recorded in 2000. CUB/AG accept the injuries and damages expense for claims that have been actually paid, but contend that the accrual should not be included in the injuries and damages expense. According to CUB/AG, this would constitute double recovery. CUB/AG note that this accrual is a reserve for potential future claims, not claims that have already occurred, and that this accrual is inconsistent with the typical methods used by IP to compute this expense. (GCI Ex. 2.0, p. 9) Since it is atypical for IP to recover both the $5.5 million accrual and claims actually paid in the test year, for injuries and damages, CUB/AG argues, the $5.5 million accrual should be completely removed from the test year. CUB/AG also argue that IP's proposal to amortize the $5.5 million accrual over a three-year period should be rejected. CUB/AG also state, however, that if the Commission chooses to phase in the accrual over three years, then in the future, there should be a rate base deduction for the accrued liability in excess of claims actually paid; the accrued liability (or reserve) would represent the cumulative recovery through rates in excess of amounts actually paid. (CUB/AG Init. Br., pp. 20-21)

(3) Commission's Analysis and Conclusion

The Commission concludes that IP's proposal to remove the $5.5 million accrual for litigation claims from test year operating expense and amortize this amount over a three-year period should be accepted. CUB/AG's proposal to disallow the $5.5 million expense in its entirety should be rejected. The Commission rejects CUB/AG's characterization that IP is seeking double recovery. There appears to be no dispute that IP properly recorded the $5.5 million accrual in 2000 in accordance with the requirements of SFAS 5, and that the $5.5 million amount is a current period expense in 2000, just like claims actually paid in that year. The Commission concludes that has IP properly responded to the unusually high level of expenses recorded in Account 925 for 2000 by removing the $5.5 million accrual from test year expenses and amortizing it over three years.

g. Amortization expense for intangible plant

(1) CUB/AG's Position

CUB/AG assert that the amortization for intangible plant included in the delivery services revenue requirement should be reduced. **A**s of December 31, 2000, the balance of intangible plant in service was $63,479,000 and the accumulated amortization of that intangible plant was $49,696,000; therefore, the net balance of intangible plant subject to amortization as of that date was $13,783,000. The annual amortization expense requested by IP is $5,659,000. CUB/AG state that at this rate of amortization, the net intangible plant will be completely amortized approximately 2.4 years after the end of the test year and only 13 months after DST rates are in place. CUB/AG assert that if the rates are in effect beyond that time, IP will be collecting in rates for an expense that it is no longer incurring. Thus, CUB/AG conclude that the amortization of intangible plant included in the delivery services revenue requirement should be modified to more accurately match the amortization expense to the value of the plant. CUB/AG recommends that the remaining net balance as of May 1, 2002 be amortized over three years, resulting in annual amortization of $2,079,000 on embedded intangible plant as of December 31, 2000, which is $3,580,000 less than the amortization of the embedded intangible plant requested by IP. (GCI Ex. 4.0, pp. 16-17) (CUB/AG Init. Br., pp. 18-19)

CUB/AG note that IP's total gas and electric balance of intangible plant as of the end of 1997 was $84,394,181. Even if new plant is added, CUB/AG argue, this existing plant will be fully amortized by 2003 because it has an amortization life of five years. According to CUB/AG the only balances left to be amortized will be additions from 1998 forward. CUB/AG assert that, in calculating its amortization expense, IP has failed to recognize that amortization of pre-1998 vintages will be expiring as the amortization of new additions begins. CUB/AG calculated the additions to intangible plant allocable to electric distribution operations for 1998, 1999 and 2000 to be $2.6 million, $0.5 million, and $1.9 million, respectively. Assuming that the additions to intangible plant continue at the rate for 1998, 1999, and 2000, CUB/AG argue, the average rate of additions will be less than $2 million per year. CUB/AG believe that the amortization of intangible plant in 2003 will be much closer to the pro forma amortization expense proposed by CUB/AG than to the amount IP is proposing. (CUB/AG Init. Br., pp. 19-20)

(2) IP's Position

IP opposes CUB/AG's proposed reduction in amortization expense for intangible plant. IP argues that this proposal must be rejected for at least two reasons. First, IP is continuing to add intangible plant. In this case, IP is proposing intangible plant capital additions to distribution rate base totaling $7,235,000 (as contrasted to a net amount of intangible plant in service at December 31, 2000 of approximately $13.8 million). (See Rev. IP Ex. 3.24, p. 1, cols. (2), (3), (4) and (7)) Therefore, IP does not expect to reach a fully amortized level of intangible plant in the foreseeable future. (IP Ex. 1.34, p. 70) Second, as Staff witness Mary Everson pointed out, the appropriate amortization rate should be determined based on the useful life of the asset being amortized, not on the frequency of the utility's rate case filings. (Staff Ex. 11.0, p. 4) IP asserts that CUB/AG have made no showing that IP's amortization rate is inappropriate based on the useful lives of its intangible plant assets. (IP Init. Br., pp. 73-74) In addition, IP notes that CUB/AG's proposed adjustment is rooted in a concern that IP's existing intangible plant will be fully amortized by about June 2003 and that from that point until the next DST rate case, customers will pay rates that include an amortization expense that IP is not incurring. IP argues that CUB/AG are pursuing a selective approach in that between the date of this Order and the next case, IP will probably incur a variety of increased costs, yet CUB/AG would not agree that adjustments should be made to the revenue requirement established in this case to take into account cost increases IP may experience in 2003.

(3) Staff's Position

With respect to CUB/AG's proposed adjustment to intangible plant amortization expense, Staff notes that, from a theoretical standpoint, the appropriate amortization rate should be determined based on the useful life of an asset, regardless of the frequency of the utility's rate case filings. (Staff Ex. 11.0, p. 4, lines 65-67) (Staff Init. Br., p. 46)

(4) Commission's Analysis and Conclusion

The Commission concludes that CUB/AG's proposed adjustment must be rejected, for at least three reasons. First, CUB/AG's adjustment is essentially premised on the completion of amortization of IP's intangible plant balance at December 31, 2000, by mid-2003, and does not recognize that IP is and will be continuing to add intangible plant. CUB/AG's attempt to show that even with additions, the intangible plant balance will be fully amortized, is speculative. Second, the Commission agrees with Staff that the amortization of intangible plant should be based on the useful lives of the assets, not on the timing of the utility's rate filing. CUB/AG have not contended that IP's amortization rate for intangible plant is inappropriate given the useful lives of the assets. Third, even if all of CUB/AG's assumptions and calculations were correct, it would be inappropriate to adopt this single adjustment based on the fact that a revenue requirement component may cease to exist in 2003, prior to the next DST case without also making adjustments for other cost changes that may occur between the date the rates set in this case go into effect and the likely date of the next DST rate order.

h. Contributions to community organizations

(1) IP's Position

IP submits that the Commission should allow inclusion of IP's contributions to community organizations that engage in economic development and related activities in IP's service area. IP states that the activities of these organizations benefit the community as a whole and IP's customers, through such activities as improving the local educational systems, providing for those families in their areas that are in need, attracting new businesses to their areas, improving the level and education of the work force, and providing assistance to businesses that have specialized needs. IP states that the efforts of these types of organizations assist customers in IP's service territory to maintain jobs or stay in business. IP contends that without this assistance, IP could likely have increased uncollectibles and decreasing sales. IP concludes that its contributions to these community organizations are a sound and prudent expense that directly benefits customers. (IP Init. Br., pp. 74-75)

IP rejects Staff witness Ms. Pearce's characterization that IP participates in these organizations for "promotional benefit". Rather, IP contends, IP belongs to, participates in, and otherwise actively supports those organizations that are geared towards the enhancement, growth and advancement of IP's service territory, and that IP's participation in the activities of these organizations is beneficial to the customers in its service area. (IP Ex. 1.63, p. 42) IP argues that Ms. Pearce's contention that contributions to these organizations should be disallowed because IP receives a "benefit" from them provides no basis for disallowing the costs. IP states that it receives "benefits" from most if not all payments it makes, such as payments of wages and salaries to its employees, and payments to suppliers for materials and equipment. Further, reduced uncollectibles in the test year would be reflected in establishing the revenue requirement, and higher sales would result in lower per-unit charges to customers to recover the revenue requirement as determined by the Commission. IP states that Staff witness Pearce acknowledged these facts. (Tr. 272-73) IP concludes that the Commission should reject Ms. Pearce's proposed disallowance of these contributions. (IP Init. Br., p. 75)

(2) Staff's Position

Staff proposes to reduce test year operating expense by $128,000, reflecting amounts paid to various chambers of commerce and community organizations (Staff Init. Br., App. A, page 8 of 13) that are more appropriately considered goodwill or promotional activities which are not necessary to provide utility service to ratepayers. (Staff Ex. 3.0, p. 4) IP accepted a portion of this adjustment, but $56,000 of it remains contested. Staff notes that IP responded that payments to these organizations could help to reduce IP's uncollectibles and increase IP's sales because the efforts of these organizations benefit IP's service territory as a whole. Staff contends that IP provided no evidence to support its assertion that payments to these types of organizations directly benefit its customers. Staff asserts that the costs in question are not necessary to provide service to IP's delivery services customers and that IP has not supported its assertion that these costs benefit its delivery services customers. Staff also believes that even if a correlation could be shown between the efforts of such organizations and lower uncollectibles and increased sales for IP, IP's shareholders would most directly benefit from such results. (Staff Ex. 12.0, p. 3) According to Staff, the Commission has accepted similar adjustments in prior orders, including for Commonwealth Edison Company in Docket No. 90-0169 and Docket 94-0065, and for CILCO in Docket Nos. 99-0119 and 99-0131 (Cons.). (See also Staff Init. Br., pp. 24-25)

. **(3) Commission's Analysis and Conclusion**

The Commission concludes that IP should be allowed to recover the remaining amount of contributions to community organizations that it has not agreed to remove from distribution operating expenses, and that Staff's proposal to disallow the remaining amount of contributions should not be accepted. The record shows, based on the activities of the organizations to which the contributions were made, that the contributions in question are beneficial to the economy and customers of IP's service area. The record shows that both IP and its customers benefit from the activities of the organizations that IP has supported through these contributions.

4. Commission's Overall Conclusion on Distribution Operating Expense

Giving effect to the adjustments to distribution operating expenses that the Commission has accepted in this Order, the Commission concludes that IP's distribution operating expenses for the test year for purposes of setting rates in this proceeding should be as follows:

Item	Amount (000)
Operation and Maintenance	$53,015.0
Customer Accounts Expense	12,163.0
Customer Service and Inform. Expense	4,488.0
Administrative & General Expense	41,682.0
Depreciation Expense – Dist. Plant	33,789.0
Depreciation Expense – General Plant	5,189.0
Amortization Expense – Intangible Plant	7,106.0
Taxes Other Than Income Taxes	33,287.0
Investment Tax Credit Adjustment – Net	(573.0)
Total Operating Expenses	$190,146.0

Giving effect to the distribution rate base and operating expense statement as found above, and the rate of return on rate base as approved in the next section of this Order, the Commission finds that IP's delivery services revenue requirement for purposes of this case is $295,950,000.

D. Cost of Capital

Evidence concerning the cost of capital and rate of return was filed by three parties in this docket, namely, Illinois Power, Staff and IIEC. In its initial filing, Illinois Power requested an overall rate of return on rate base of 9.22%, including a 12.50% rate of return on common equity. (IP Ex. 3.2) During the course of these proceedings, however, IP, Staff and IIEC reached agreement on the rate of return, including the components thereof, that should be adopted for purposes of setting rates in this proceeding. The agreed rate of return is 8.69%. No other party raised any objection to the agreed rate of return. The agreed rate of return, including the components thereof, were presented by Staff's cost of capital witness, Rochelle Langfeldt, in Staff Exhibit 20.0, and are as follows (IP Init. Br., pp. 75-76):

COST OF CAPITAL SUMMARY

August 31, 2001

Capital Component	Balance	Ratio	Cost Rate	Weighted Rate
Long-term debt	$1,095,159,675	34.40%	7.01%	2.41%
Transitional Funding Instruments	592,048,011	18.60%	7.01%	1.30%
Short-term debt	170,032,566	5.34%	3.98%	0.21%
Preferred Stock, non-tax advantaged	45,430,145	1.43%	5.05%	0.07%
Preferred Securities, tax-advantaged	94,297,622	2.96%	8.63%	0.26%
Common Equity	1,186,423,425	37.27%	11.89%	4.43%
Total	$3,183,391,444	100.00%		8.69%

As Ms. Langfeldt explained, the 11.89% rate of return on common equity that was used in arriving at the overall rate of return of 8.69% is Staff's recommended rate of return on common equity, which she supported in her prepared testimony and exhibits (Staff Exs. 4.0 and 13.0) that were admitted into evidence. As she also explained, the other components of the capital structure were determined using a measurement date of August 31, 2001. (Tr. 574-75) (IP Init. Br., p. 76)

Based on the evidence presented by Staff witness Langfeldt explaining and supporting the components of the overall cost of capital, including the rate of return on common equity of 11.89% as supported in her prepared testimony, as well as the agreement of the parties, the Commission finds the cost of capital shown in the foregoing table to be reasonable and supported by the evidence, and concludes that the rate of return on rate base of 8.69% should be utilized for purposes of setting distribution rates in this proceeding. (See IP Init. Br., p. 76)

III. COST OF SERVICE AND RATE DESIGN

A. Cost of Service Study

1. Overview of Embedded Cost of Service Study

a. IP's Position

In its direct case filing, IP submitted an embedded cost of service study ("ECOSS") for the distribution revenue requirement that determined cost responsibility by customer class. IP also submitted a study calculating the revenue requirement and class cost responsibility for meters subject to unbundling. (IP Ex. 8.1, pp. 2-4, 8-9; IP Exs. 8.2, 8.8-8.9) A revised ECOSS and revised unbundled meter revenue requirement and cost of service study were submitted as part of IP's rebuttal filing, reflecting various corrections and changes, modifications in response to certain recommendations by other parties, and changes in the level of detail presented. (IP Ex. 8.10, pp. 2-3, 9-10; IP Exs. 8.11, 8.14-8.15) IP submits that, in general, its ECOSS was prepared consistently with the methodologies used in the 1999 DST Case. The revenue requirement for meters subject to unbundling was determined using the same methodologies approved by the Commission in Docket 99-0013, the meter unbundling case. (IP Ex. 8.1, p. 8; IP Ex. 8.10, p. 9) The ECOSS results and unbundled meter revenue requirement that IP believes should be used for purposes of this case are shown in the following exhibits: (1) ECOSS for the distribution business – IP Exhibit 8.11; (2) revenue requirement for meters subject to unbundling – IP Exhibit 8.14; and (3) ECOSS for the meter revenue requirement – IP Exhibit 8.15. (IP Init. Br., p. 77)

Illinois Power acknowledges that witnesses for Staff, IIEC and CUB/AG criticized several specific aspects of its cost of service studies and of their use in setting specific rates and charges in this case. IP states that in general, however, it appears that the cost of service witnesses for the other parties have accepted IP's ECOSS for use in this case, subject to certain specific modifications that each may have proposed. (Staff Ex. 5.0, p. 20 and Tr. 724-26 (Lazare, Staff); IIEC Ex. 6, p. 13 (Phillips, IIEC); GCI Ex. 3, p. 7 (Smith, CUB/AG)) No party presented a separate cost of service study. (IP Init. Br., pp. 77-78)

b. IIEC's Position

IIEC asserts that IP's originally filed cost of service study contained numerous flaws and errors such that it had no use or purpose in this proceeding. (IIEC Ex. 3, pp. 11-19; IIEC Ex. 6, pp. 6-9) IIEC contends that even though the IP rebuttal ECOSS corrects some of the errors and mistakes from the originally filed cost of service study, it still has its problems. For example, though the rebuttal cost of service study contains lower per unit rates for most elements of the over 1,000 kW segment of the demand metered rate class as compared to the originally filed cost of service study, the percentage increase for this class is approximately three times as large as the percentage increase as originally filed. IIEC asserts that this anomaly was not explained by IP. (IIEC Ex. 6, p. 15) Given the timing of the rebuttal ECOSS filing, IIEC asserts that there was no opportunity to verify all the results of the purported corrections, changes and updates. IIEC notes that many values in IP's rebuttal ECOSS were significantly different from the original quantities as provided in the ECOSS filed in IP's direct case. (IIEC Ex. 6, p. 15) (IIEC Init. Br., pp. 13-14)

Nonetheless, it is IIEC's position that the IP rebuttal cost of service study may have a limited use as a basis for determining the percentage of net revenue requirement attributable to each rate class. IIEC witness Mr. Phillips testified that the percentages appear to be relatively constant and somewhat consistent with the Commission findings in the 1999 DST Case. (IIEC Ex. 6, p. 13). IIEC suggests that, given the limited value of the IP rebuttal cost of service study, it is critically important that the Commission fairly determine the appropriate level of A&G expense and G&I plant in order to ensure that ratepayers only pay the costs that are proper and justified. According to IIEC, IP's allocation techniques concerning A&G expense and G&I Plant are not sufficient given the magnitude of the costs to be recovered. The level of these expenses are so large in IP's cost of service studies, IIEC contends, that they distort the results of the study. For these reasons, while IIEC supports the use of IP's rebuttal ECOSS for allocation of revenue responsibility to the major delivery service customer classes, it does not support its use for rate design purposes for the demand metered customer classes. Instead, IIEC proposes that facilities charges, metering charges and demand charges for the demand-metered class should be increased on an equal percentage basis to the overall class revenue increase. (IIEC Init. Br., p. 14)

2. Specific Cost of Service Study Issues

a. Allocation of miscellaneous revenues to the customer classes

(1) IP's Position

Illinois Power allocated miscellaneous revenues to the customer classes in IP's ECOSS. In response to CUB/AG witness Smith's criticism of this allocation, IP explains that miscellaneous revenues received from customers serve to reduce the net revenue requirement that must be recovered through the base charges for distribution service. IP notes that Ms. Smith's position was that miscellaneous revenues should be allocated to the customer classes on the same basis as the costs incurred to produce those revenues (except for those miscellaneous revenues that do not have underlying costs), and that using IP's ECOSS, she reallocated miscellaneous revenues to the customer classes on the same basis as Distribution Labor Operating Expense. (GCI Ex. 1, pp. 7-9; GCI Ex. 3, pp. 2-3; Tr. 898-99) (IP Init. Br., p. 78)

IP rejects Ms. Smith's reallocation of miscellaneous revenues as inappropriate. IP Exhibit 8.12 shows the Company's allocation of miscellaneous revenues, by type, to the rate classes. IP notes that, as the exhibit shows, the largest categories of miscellaneous revenues are forfeited discounts, equipment rentals, and service activation fees; these three categories account for about $7.9 million of the $9.4 million of test year miscellaneous revenues. Forfeited discounts (i.e., late payment charges) and service activation fees were allocated directly to the customer classes to which the forfeited discounts and service activation fees were billed, resulting in 66% of the total forfeited discounts and 95% of the service activation fee revenue being allocated to the residential class. (IP Ex. 8.10, p. 6) Equipment rental revenues were allocated to the non-residential customer classes because these rental revenues come from large customers renting transformers, customer substations and customer metering equipment. IP explains that no equipment rental revenue was allocated to the residential class because residential customers do not need to rent this type of equipment. (Id.) (IP Init. Br., pp. 78-79)

IP also disagrees with CUB/AG witness Smith's contention that a portion of equipment rental revenues should be allocated to the residential class because the costs of transformers and substations that IP rents to customers are recorded in accounts that are allocated to the residential class. (GCI Ex. 1, pp. 7-8) IP asserts that this is incomplete reasoning. IP states that the costs of the plant investment and related expenses are allocated to the customer classes, including residential, on the basis of their respective cost of service responsibilities. (Tr. 516) IP submits that this produces a fair allocation of the underlying costs, which Ms. Smith did not challenge. However, IP notes, the non-residential classes (in particular the demand-metered classes) make a contribution to recovery of their allocated share of these costs through the payment of rental revenues. (Tr. 517) IP explains that residential customers do not rent this equipment, and therefore the residential class does not make any contribution to its allocated share of these costs through the payment of rental revenues. (Tr. 516-17) Thus, IP maintains, it has appropriately allocated the equipment rental revenues to the customer classes that pay the rents (i.e., non-residential), since these rental payments reduce the amount of these classes' revenue requirement responsibility that must be recovered through the base distribution rates. (IP Init. Br., pp. 79-80)

(2) CUB/AG's Position

CUB/AG assert that the underlying driver of miscellaneous revenues is the service that gives rise to those revenues. According to CUB/AG, the services IP provides that give rise to the miscellaneous revenues are largely provided by IP employees and/or IP equipment. Consequently, CUB/AG argues, IP allocates the cost of those services to all classes. CUB/AG contends that IP's method creates a mismatch between the allocation of the underlying costs and the allocation of the revenues produced by those costs. CUB/AG states that IP allocated equipment rental revenue, which represents the majority of miscellaneous revenues, according to the classes that paid the rental fees, instead of according to the classes that were allocated the underlying equipment expenses. CUB/AG states that its witness Ms. Smith recognized the inconsistency in IP's approach and adjusted the Company's ECOSS to reflect an allocation of revenue on the same basis as the allocation of Distribution Operating Labor expense. (CUB/AG Init. Br., pp. 23-24)

(3) Commission's Analysis and Conclusion

Based on its review of the record, the Commission concludes that IP's ECOSS uses the more appropriate allocation of miscellaneous revenues to the customer classes. With respect to revenues from equipment rentals, which appears to be the major category of miscellaneous revenues in dispute, the Commission agrees with IP's explanation, that is, that the ECOSS properly allocates the costs of the substations and other rented equipment to the customer classes based on cost of service responsibility, and then allocates the rental revenues to those classes that contribute to the recovery of their allocated cost of service through the payment of rental charges. In addition, the Commission notes that CUB/AG witness Smith's use of Distribution Operating Labor as the allocation factor for all miscellaneous revenues is clearly inappropriate with respect to a number of categories of miscellaneous revenues, such forfeited discounts.

b. Use of replacement costs to allocate costs of meters and service lines to the customer classes

In its ECOSS, IP used the replacement (i.e., current) costs of the meters and services that serve each customer class as the basis for allocating the embedded costs of meters and service drops to the customer classes. In response to IIEC's criticism of the use of replacement cost information in an embedded cost study, IP maintains that its allocation methodology for meter and service drop costs was well-founded and appropriate. IP explains that the same type of meter is not used to serve all customer classes. Rather, meters used to serve larger, demand-metered non-residential customers are more complex, and therefore more costly, than the meters used to serve residential and small use general service customers. (IP Ex. 8.16, pp. 2-3; Tr. 517-19) IP cites page 98 of the NARUC Electric Utility Cost Allocation Manual, which states, "The metering account is a clear example of an account requiring weightings for differences between classes. A metering arrangement for a single industrial customer may be 20 to 80 times as costly as the metering for one residential customer." (Tr. 518) IP states that because its meters and services are mass-accounted in Accounts 370 and 369, it is not possible to separately identify from IP's accounting records the embedded costs of the types of meters used to serve residential customers and the embedded costs of the more complex meters used to serve demand-metered customers. (IP Ex. 8.16, pp. 2-3) IP states that as a result, it used current replacement costs for the types of meters and services used to serve each customer class in allocating the investment in Accounts 369 and 370 to the customer classes. Specifically, (1) the replacement costs to serve each class of customers were multiplied by the number of customers in each rate class; (2) these products were then summed; (3) the replacement costs for each rate class were divided by the total replacement costs (item (1) divided by item (2)) to derive a percentage of the total for each class; and (4) the percentage for each class was then multiplied by the embedded costs in the meters and services asset accounts to allocate the embedded costs to the rate classes. IP notes that this approach is supported by the NARUC Electric Utility Cost Allocation Manual (See IP Ex. 8.16, p. 3) and that it is also consistent with the method of allocating meters and services to the rate classes that was used in IP's 1999 DST Case. (IP Ex. 8.10, p. 4) (IP Init. Br., pp. 80-81)

Based on the explanation of its approach provided by IP, the Commission concludes that the methodology IP used to allocate its embedded cost investment in meters and services to the customer classes was well-supported and appropriate.

c. G&I plant and A&G expense included in revenue requirement for meters subject to unbundling

IP's cost of service witness, Karen Althoff, explained that G&I plant and A&G expense were allocated to the metering function on the same basis as approved by the Commission in Docket 99-0013, namely, based on the relationship of meter service labor to total electric distribution labor. Meter service labor was 18.08% of total electric distribution labor; this percentage was applied to electric distribution G&I plant and A&G expenses to determine the amounts of G&I plant and A&G expenses to be allocated to the metering function. (IP Ex. 8.10, pp. 9-10; IP Ex. 8.16, pp. 7-8) IP notes that IIEC witness Phillips' expressed concern over the amount of A&G expense and G&I plant allocated to the metering function; however, IP states that IIEC did not provide any alternative approach and did not dispute the fact that the allocation of G&I plant and A&G expenses was made in the same manner as approved in Docket 99-0013.

(IP Init. Br., pp. 81-82)

The Commission concludes that IP appropriately allocated A&G expense and G&I plant to the metering function based on the same methodology that was followed in the meter unbundling case, Docket 99 0013.

3. Commission's Overall Conclusion on Use of IP's Embedded Cost of Service Study

Based on its review of the record, the Commission concludes that the ECOSS presented by IP in its rebuttal testimony should be used for purposes of revenue allocation and rate design in this case. No other party presented an embedded cost of service study in this proceeding, and with the exception of certain specific adjustments or criticisms that IIEC and CUB/AG presented, the parties appear to have accepted the use of IP's rebuttal ECOSS in general for use in this proceeding. The Commission notes that to the extent other factors than strict application of the cost of service study results, such as maintaining rate continuity, are applicable to the setting of specific rates and charges in SC 110, those considerations are discussed and taken into account as appropriate in the section of this Order on DST Rate Design.

B. Allocation of the Distribution Revenue Requirement to the Customer Classes

IP proposes that the distribution revenue requirement be allocated among the delivery services customer classes on the basis of the embedded cost of service study results, with no deviations from cost of service based on other considerations. (IP Ex. 6.6, p. 2) IP notes that Staff witness Lazare also testified that the revenue requirement should be allocated solely based on cost of service. (Staff Ex. 5.0, pp. 20-23; Tr. 726) No other witness proposed any deviations from cost of service as the basis for allocating the distribution revenue requirement to the customer classes. (IP Init. Br., p. 82) In its Initial Brief, IIEC also indicated that it accepted IP's rebuttal ECOSS for use in allocating the revenue requirement among the customer classes. (IIEC Init. Br., p. 14) Accordingly, based on the record and the agreement of the parties, the Commission concludes that the final approved distribution revenue requirement should be allocated to the customer classes on the basis of the ECOSS presented by IP in rebuttal.

C. Delivery Services Tariff Rate Design.

1. Residential

a. Facilities Charges

Illinois Power, Staff and CUB/AG agree that the residential DST facilities charges should be set equal to the current facilities charges in the bundled rates, adjusted for the 5% statutorily-mandated residential rate decrease scheduled for May 1, 2002. (IP Ex. 6.6, pp. 6-7; Staff Ex. 14.0, p. 18; GCI Ex. 3, pp. 3-4; Tr. 727, 900-01) In other words, the residential DST facilities charges should be set equal to the facilities charges that will be in effect beginning May 1, 2002. This approach will promote rate continuity as residential customers become eligible to move from bundled tariffs to delivery services beginning May 1, 2002. (Tr. 901) (IP Init. Br., pp. 82-83)

The Commission agrees with the analysis and reasoning presented by IP, Staff and CUB/AG. Accordingly, the three categories of residential DST facilities charges (single-family, multi-family and three-phase) shall be set equal to the corresponding bundled residential facilities charges that will be in effect beginning May 1, 2002, upon implementation of the statutorily-mandated 5% residential rate decrease that goes into effect on that date. These facilities charges are $5.96 per month for single-phase, multi-family installations; $7.96 per month for single-phase, single-family installations; and $16.00 for three-phase service.

b. Delivery Charge

(1) IP's Position

Illinois Power rate design witness Jones and CUB/AG rate design witness Smith agreed that the residential DST delivery charge should be a two-block structure with the first block set at 300 kWh per month, the same structure as the energy charge in the current residential bundled rate, SC 2. (However, they disagree on the price differential that should be established between the first block and the tailblock.) (IP Ex. 6.1, p. 12; IP Ex. 6.11, p. 1; GCI Ex. 3, Sched. LS-6) IP states that Staff witness Lazare, in contrast, proposed a flat residential delivery charge. (Staff Ex. 14.0, p. 20; Staff Ex. 22.0, Sched. 14.3 Rev.) IP urges the commission to reject Mr. Lazare's proposal and adopt a blocked delivery charge structure as recommended by IP witness Jones and CUB/AG witness Smith. IP contends that, as is the case with the agreed residential DST facilities charge, implementing a two block residential DST delivery charge will maintain rate continuity with the residential bundled rates. IP notes that both the Company and CUB/AG witness Smith believe that maintaining rate continuity for residential customers is an important consideration as they become eligible to switch to delivery services. (IP Ex. 6.6, p. 7; GCI Ex. 1, p. 14) In addition, IP asserts that a two block delivery charge for residential customers better matches the pricing to how local low voltage costs (i.e., secondary distribution facilities costs) are incurred. According to IP, local secondary facilities (lines and transformers) may serve from one to a few customers and are sized to meet the customers' maximum demands. Therefore, IP concludes, these costs are appropriately recovered through the facilities charge, or, as IP is proposing, through a first block delivery charge. (IP Ex. 6.6, pp. 11-12) (IP Init. Br., p. 83)

IP notes that Mr. Lazare advocated a flat residential delivery charge in order to encourage conservation. (Staff Ex. 5.0, pp. 37-39; Staff Ex. 14.0, pp. 19-20) IP questions whether conservation should be a consideration in setting rates for a delivery company that does not supply energy. (IP Ex. 6.6, p. 8) IP believes that it is also questionable whether the small difference between the IP's proposed residential tailblock rate (2.022 cents/kWh, see IP Ex. 6.11, p. 1) and Mr. Lazare's proposed flat residential delivery charge (2.486 cents/kWh, see Staff Ex. 22.0, Sched. 14.3 Rev.), less than ½ cent per kWh, will provide any sort of meaningful conservation signal to residential delivery services customers. IP maintains that price signals sent to customers through rate design should reflect the cost of serving the customer, and that cost-based rates provide the most appropriate price signals. IP states that attempting to promote conservation by implementing charges that do not reflect cost of service is an inappropriate objective. (IP Init. Br., p. 84)

IP states that secondary facilities are installed as a function of the number of customers and the expected demand on the facilities, and that the secondary system cost is heavily weighted toward a function of the customer being connected to the utility's system. According to IP, the demand or usage-sensitive portion of the cost of secondary facilities is relatively small. Therefore, IP argues, it is appropriate to recover these costs in a relatively small usage block in the delivery charge. IP has set the initial block at 300 kWh for these purposes. IP explains that 80% of IP residential customers use at least 300 kWh per month; further, this blocking is identical to the residential bundled rate, SC 2. (IP Ex. 6.1, pp. 11-12; IP Ex. 6.6, pp. 8-10) IP states that in addition, the cost per kWh of secondary facilities installed to serve residential customers decreases as the customer's size (in terms of average kWh usage per month) increases (even though the total secondary facilities cost of service increases as the size of the customer increases). (IP Ex. 6.6, pp. 8-9; Rev. IP 6.12) Therefore, IP believes that use of a flat residential delivery charge as proposed by Mr. Lazare would inappropriately shift cost recovery from smaller use customers to larger use customers. (IP Ex. 6.14, pp. 7-8) (IP Init. Br., pp. 84-85)

IP proposes that the differential between the first and second blocks in the delivery charge should be 1.4 cents per kWh. This is the load-weighted average of the differentials between the first and second block in the SC 2 (bundled) residential energy charge for the summer and winter seasons that will be in effect commencing May 1, 2002 (i.e., reflecting the mandated 5% residential bundled rate reduction). (IP Ex. 6.6, p. 6) IP notes that while CUB/AG witness Smith agreed with IP that the residential DST delivery charge should have two blocks, with the first block set at 300 kWh per month, she proposed a differential of only 0.8 cents per kWh between the blocks, which reflects only the summer season differential and ignores the winter season differential in SC 2. (GCI Ex. 3, Sched. LS-6; IP Ex. 6.6, p. 6) IP acknowledges that the 1.4 cent/kWh differential is somewhat higher than the cost-based differential (i.e., the differential that would be based strictly on the recovery of secondary facilities costs in the first block). (IP Ex. 6.14, p. 5) However, IP points out that the agreed residential DST facilities charges for single and multi-family service are somewhat below cost, while the agreed residential DST facilities charges for three-phase service (i.e., the largest use customers) are somewhat above cost. IP concludes that taken together, its proposed facilities charges plus first block delivery charge will appropriately recover facilities and secondary demand costs, for both smaller-use and larger use customers. (IP Ex. 6.14, pp. 5-6; Tr. 872-73) (IP Init. Br., pp. 85-86)

In summary, IP asserts that its proposed residential DST delivery charge rate design best promotes the twin objectives of proper cost recovery and maintaining rate continuity with the residential bundled rates and should, therefore, be approved by the Commission. (IP Init. Br., p. 86)

(2) CUB/AG's Position

CUB/AG agrees with IP's proposal for a declining block delivery charge for residential DST customers, with the initial block set at 300 kWh, primarily in order to maintain rate continuity with the existing residential bundled rates. However, CUB/AG disagree with IP's proposed differential of 1.4 cents/kWh between the first and second blocks. CUB/AG's position is that the differential between the blocks should be set at 0.8 cents/kWH. CUB/AG suggest that IP overstates the local low voltage costs required to serve residential customers, and therefore its rate design does not appropriately reflect cost incurrence. CUB/AG contend that the distribution system must be sized to meet maximum demand in order to both satisfy demand and maintain system reliability. By attempting to recover secondary distribution costs entirely through the first block charge, CUB/AG argue, IP's approach improperly allocates the average cost of distribution plant to every customer. CUB/AG argue that this approach makes delivery charges less affordable to smaller users, in contradiction of the principle of universal service, and significantly reduces the usage sensitivity of local secondary facilities for all consumers that use more electricity on a monthly basis. CUB/AG argue that the Commission must ensure that small residential customers do not pay more than their fair share of costs. (See CUB/AG Init. Br., pp. 25-27)

CUB/AG support the consideration of environmental energy conservation in rate design both because of the uncaptured external costs of production and delivery, and the impact of increased stress on transmission and distribution systems that results from additional peak time usage. CUB/AG note that Staff witness Lazare recommends recovering the costs of secondary distribution system in a single flat rate on all kWhs delivered to residential customers, and that flat rates send consumers in higher usage brackets a more appropriate price signal to conserve energy. Though CUB/AG agree with Staff's theoretical argument, CUB/AG propose a declining block rate, but one that is less steep than the rate proposed by IP. CUB/AG explain that their proposal is meant to maintain continuity between the delivery service and bundled service rates, to facilitate customer understanding, another important policy objective in rate design. (CUB/AG Init. Br., pp. 27-28)

With respect to the level of differential in the declining block structure, CUB/AG note IP's proposal presented in rebuttal is 0.14 cents/kWh higher than the differential IP originally proposed in its direct testimony, and is 0.6 cents/kWh higher than the proposal presented by CUB/AG witness Smith in her rebuttal. CUB/AG contend that IP's differential is higher than the cost-based differential. CUB/AG argue that under IP's approach, some customers will pay for more facilities than they use, and that the revenues resulting from IP's proposed higher first block would be greater than the cost the Company has computed for the residential share of the distribution system. CUB/AG argue that IP failed to provide sufficient evidence to support the proposed level of the first block and the differential between the blocks. CUB/AG contend that the only justification IP has provided for the proposed differential is that the agreed residential facilities charges are set below costs and therefore the total rate design balances out. CUB/AG argue that this is insufficient justification for a rate design which produces the result, according to CUB/AG, that smaller use customers pay more of the class revenue requirement. (CUB/AG Init. Br., pp. 28-29)

CUB/AG also criticize IP Exhibit 6.12 which illustrates a comparison of two residential circuits: one serving 6 customers using 300 kWh per month and one serving 6 customers using 3,000 kWh per month. CUB/AG note that this exhibit shows that the per kWh cost of serving a large residential customer is smaller than the per kWh cost of serving a small residential customer, but assert that the exhibit is flawed on many levels. According to CUB/AG, the hypothetical in IP Exhibit 6.12 proves neither the general proposition that costs per kWh decrease significantly with size of customers nor that the cost per kWh decreases significantly as customers get larger. CUB/AG state that the exhibit is very specific and depends on many assumptions, and suggest that changes in the assumptions used in the exhibit could produce different results. CUB/AG note that both Staff witness Lazare and CUB/AG witness Smith questioned the assumptions used to develop this exhibit. CUB/AG contend that the hypothetical does not justify IP's attempt to recover secondary distribution facilities costs on a per customer basis. (CUB/AG Init. Br., p. 30)

(3) Staff's Position

Staff asserts that delivery charges for residential (and small use general service) customers should have a flat, rather than declining block, structure. Staff contends that IP's arguments in support of a two-block delivery charge for these classes, with the dividing point between the two blocks set at 300 kWhs per month, are inherently flawed because IP has failed to explain why the costs of local secondary facilities should be recovered solely from the first 300 kWhs delivered to customers each month. (Staff Ex. 5.0, p. 37) According to Staff, the cost of service indicates that these costs should be recovered over all monthly usage, because (1) secondary facilities are sized to meet the expected maximum demands of customers, and (2) the greater the consumption by a customer, the higher will be that customer's peak demand. Staff contends that the demands that contribute to secondary facilities costs are shaped by all usage, not just the first 300 kWhs. Thus, Staff believes that it would be reasonable to assume that a customer using 3,000 kWhs per month would require larger secondary facilities than a customer using 300 kWhs per month. Nevertheless, IP proposes that both customers pay the same amount for local secondary facilities. Staff contends that a flat delivery charge would more appropriately recovering these costs over all kWhs of delivery service. Staff also contends that a flat rate would offer the further advantage of sending consumers in higher usage brackets a more appropriate price signal to conserve energy. Staff believes that the higher rate applying to higher usage levels would encourage these customers to reduce wasteful consumption, thereby mitigating upward pressures on power prices. Furthermore, Staff argues that there would be environmental benefits as well. (Staff Ex. 5.0, pp. 38-39) (Staff Init. Br., pp. 58-60)

(4) Commission's Analysis and Conclusion

The Commission agrees with IP and CUB/AG that the residential DST delivery charge should be a two-block structure with the first block set at 300 kWh. The Commission concludes that this rate structure is more appropriate on rate continuity grounds than a flat delivery charge, particularly as residential customers face their initial opportunity to move from bundled rates to delivery services. Further, although the parties have debated the extent of the usage sensitivity of secondary (low-voltage) distribution facilities serving residential customers, it is clear from the record that a significant driver of the costs of secondary facilities is simply the need to connect customers to the system. Accordingly, these costs do not vary directly with the amount of the customer's monthly usage, and there is no justification for a flat charge as proposed by Staff. While the Commission appreciates that a higher tailblock charge may, in theory, encourage conservation, the Commission believes that such price signals must be based on costs. Accordingly, the Commission does not agree with Staff's proposal for a flat residential DST delivery rate.

The Commission concludes that the differential between the first and second blocks in the delivery charge should be set at 1.4 cents as proposed by IP. Setting the differential at 0.8 cents as proposed by CUB/AG would not be reflective of the differential in all seasons of the year. Further, in light of the fact that 80% of IP residential customers use at least 300 kWh per month, the combination of the facilities charge and the first block charge needs to approximate the overall cost of service for customer facilities and secondary facilities. The record shows that the differential proposed by IP, in combination with the agreed residential facilities charges, better accomplishes this objective than does the differential proposed by CUB/AG.

2. Small Use General Service DST Rate Design

a. Facilities Charges

Based on the distribution revenue requirement it proposed in its rebuttal filing and the allocation thereof to the small use general service class based on the ECOSS, IP proposes facilities charges for small use general service DST customers of $8.03 and $11.09 for single-phase and three-phase service, respectively. IP also proposes a facilities charge for unmetered service DST customers of $8.50. (IP Ex. 6.6, p. 11; IP Ex. 6.11, p. 1) IP notes that Staff witness Lazare, the only other witness to address rate design for this customer class, offered no criticisms of IP's proposed facilities charges, yet he proposed facilities charges for this class (to recover the same revenue requirement) of $5.35 and $7.39 for single-phase and three-phase service, respectively. (Staff Ex. 22.0, Sched. 14.4 Rev.) IP states that although Mr. Lazare's rate design exhibit stated that one of his proposals was to "prorate Company-proposed customer, metering and demand charges to conform to applicable costs as determined under IP's cost of service study" (Staff Ex. 22.0), his proposal would move the small use general service facilities charges below cost of service. (See IP Ex. 6.14, p. 10 and Rev. IP 6.10, Sched. 2, Item 1, p. 5) IP notes that Mr. Lazare offered no other offsetting considerations to justify rates different from IP's proposal. IP states that its proposed facilities charges for the small use general service class mitigate some of the rate impact of moving the prices to cost of service immediately. (IP Ex. 6.6, p. 10) IP contends that its proposed facilities charges provide a greater degree of rate continuity and maintain the relationships between individual facilities charges and meter charges as well as costs within the small use general service class. IP concludes that its proposal provides for a progression to move prices closer to cost of service and should be adopted. (See IP Ex. 6.14, p. 10) (IP Init. Br., pp. 86-87)

Based on its review of the record, including the explanation provided by IP for its proposed facilities charges, and examination of the facilities charges proposed by Staff on Staff Exhibit 22.0, the Commission concludes that the facilities charges proposed by IP for the small use general service class are more appropriate taking into account cost of service, rate continuity and customer impact considerations, and should be adopted.

b. Delivery Charge

(1) IP's Position

IP proposes a two-block delivery charge for the small use general service class with the first block set at 300 kWh per month. IP proposes this structure on the same bases as the residential DST delivery charge. (IP Ex. 6.1, p. 13; IP Ex. 6.6, p. 11) IP opposes Staff witness Lazare's proposal for a flat delivery charge for small use general service DST customers, which he based on the same arguments as his proposal for a flat delivery charge for residential DST customers. (Staff Ex. 14.0, p. 23) IP notes that the small use general service customers tend to use less energy than the average residential customer. Further, IP adds, small use general service customers are even less likely than are residential customers to share secondary facilities (lines and transformers), which would otherwise reduce the average secondary facilities costs per customer and per kWh. Thus, IP argues, the cost recovery reasons that support use of a blocked DST delivery charge are even stronger for small use general service customers than for residential customers. (IP Ex. 6.14, p. 9) In addition, IP contends that Mr. Lazare's proposed flat delivery charge for this class recovers more revenue that IP's delivery charge due to the need to recover the remaining class revenue requirement that results from his proposed facilities charges being lower than those IP has proposed. (IP Init. Br., pp. 87-88) IP also notes that while the current SC 110 delivery charge for this class is flat, the current energy charge in the bundled rate applicable to these customers has a block structure. IP states that in light of the fact that at this time very few small use general service customers have availed themselves of delivery services, it is more important to maintain rate continuity between the bundled rate for this class and the delivery charge in their DST rate, than it is to maintain continuity with the existing DST rates for this class.

With respect to unmetered service, IP notes that Staff witness Lazare proposes to increase the delivery charge by 1176%. (IP Ex. 6.6, p. 12) IP contends that the need for this large increase is the result of Mr. Lazare's proposal to reduce the unmetered service facilities charge. (See Staff Ex. 22.0, Sched. 14.4 Rev.) IP proposes to keep the unmetered service facilities charge at its current level ($8.50 per month), which enables IP to mitigate the increase needed in the delivery charge in order to achieve cost recovery. (IP Ex. 6.6, p. 12) (IP Init. Br., p. 88)

(2) Staff's Position

Staff proposes a flat delivery charge for the small use general service class, for the same reasons that Staff proposed a flat delivery charge for residential DST customers, as summarized in the section of this Order pertaining to the residential DST delivery charge.

(3) Commission's Analysis and Conclusion

Based on its review of the record, the Commission concludes that the delivery charge for small use general service DST customers should have a two-block, declining block structure. The Commission bases its conclusion on the same reasons that support the decision to adopt a two-block structure for the residential DST delivery charge, as discussed earlier in this Order. The delivery charge structure proposed by IP for this class is more appropriate than Staff's proposal, on cost of service and rate continuity grounds.

3. Demand Metered General Service DST Rate Design

a. Facilities Charges

(2) IP's Position

IP states that the ECOSS shows that, in general, the current facilities charges and metering charges for the demand-metered general service class do not match the overall cost of service for these components. IP proposes to set the metering charge at cost of service, since this is an unbundled service that can be provided by others, and to change the facilities charges by one-half of the amount necessary to reach cost of service recovery. IP believes that this approach will mitigate the disparate impacts on the subclasses within the demand-metered class that would result from full movement to cost of service in this case. (IP Ex. 6.6, pp. 10-11; Rev. IP Ex. 6.10) IP notes that Staff witness Lazare proposed facilities charges that were scaled down from IP's proposed facilities charges. (See IP Ex. 6.14, pp. 9-10, and Staff Ex. 22.0, Sched. 14.5 Rev.) IP argues that, in general, its proposed facilities charges are closer to cost of service than Mr. Lazare's proposed charges, represent a considered step in moving to full cost-based facilities charges, and provide a greater degree of rate continuity. Accordingly, IP argues, IP's proposed facilities charges for this class, rather than Mr. Lazare's, should be adopted. (IP Init. Br., pp. 88-89)

(3) IIEC's Position

IIEC supports an equal percentage increase in the facilities charges, metering charges and demand charges for the demand-metered class, for the reasons stated in Section III.A.1.b of this Order. (IIEC Init. Br., p. 14)

(4) Commission's Analysis and Conclusion

The Commission concludes that the facilities charges proposed by IP for the demand-metered class should be adopted. The Commission rejects IIEC's proposal for an equal percentage increase in facilities, metering and demand charges for this class, as not based on cost of service. IIEC's criticisms of IP's ECOSS are not sufficient to warrant departing from cost of service as the primary basis for setting these charges.

b. Demand Charges and Distribution Capacity Charges

(1) IP's Position

IP proposes to implement a distribution capacity charge for demand-metered DST customers taking service at 12.47 kV and below. The distribution capacity charge is designed to recover the cost of local low-voltage facilities that for the most part do not share in the load diversity of the larger system. The distribution capacity charge will be billed on the basis of the customer's maximum demand in the preceding 12 months, which IP states provides a better fit to the manner in which the costs of low voltage facilities are incurred. IP states that the distribution capacity charge will, therefore, operate identically to the distribution capacity charge that is included in IP's bundled rates for demand-metered customers. (IP Ex. 6.1, pp. 15-16) (IP Init. Br., p. 89)

IP states that the remaining demand charge will recover the cost of high-voltage facilities, which are designed primarily based on the diversity of several customers' loads. The demand charge will be billed based on the customer's maximum monthly demand. This is the basis for billing the current DST demand charges. IP notes that Staff found IP's demand charge methodology to be generally acceptable. (See Staff Ex. 14.0, pp. 22-23) (IP Init. Br., pp. 89-90)

IP responded to Staff witness Lazare's objection to IP's proposal to establish a separate distribution capacity charge. IP notes that the principal basis for Mr. Lazare's objection was that basing this charge on the customer's maximum demands during the preceding 12 months provides no incentive to the customer to control its monthly demands, so long as the monthly demands stay below the maximum demand in the prior 12 months, and that he also questioned whether distribution costs are in fact driven by individual maximum demands and do not benefit from the diversity of the overall system. (Staff Ex. 5.0, pp. 30-33; Staff Ex. 14.0, pp. 23-25) In response, IP states that the proposed distribution capacity charge based on the customer's maximum demand in the prior 12 months is consistent with cost of service principles, because it is annual customer peak demand that drives distribution investment. IP states that the ECOSS in this case uses annual non-coincident peak demand to allocate distribution costs, and that Mr. Lazare did not take issue with this cost allocation method in IP's ECOSS. In addition, once the customer has established a particular maximum demand, the distribution system must be ready to serve that level of demand in the future. (IP Ex. 6.6, pp. 18-19) Moreover, IP contends that contrary to Mr. Lazare's assertion, the customer will still have an incentive to control its monthly demands, in order to be able to reduce its distribution capacity charge after 12 months pass since the prior maximum demand was established. Further, the fact that under IP's proposed rate design there will still be a separate demand charge, billed on the basis of the customer's maximum monthly demand, will continue to give the customer a direct incentive to control the monthly demands. Finally, separation of the present demand charge into the proposed distribution capacity charge (billed on the basis of maximum demand in the prior 12 months) and a demand charge (billed on the basis of maximum monthly demand) helps to prevent high load factor customers from subsidizing low load factor customers. (IP Ex. 6.6, pp. 19-20) (IP Init. Br., pp. 90-91)

In response to Mr. Lazare's argument that the Commission has recently disapproved of the use of annual demand ratchets such as would be applied to bill the proposed distribution capacity charge, IP states that in the cases Mr. Lazare relied on, the utility was attempting to recover the entire delivery service charge using a demand ratchet. Here, IP is only proposing to use an annual demand ratchet for the distribution capacity charge, which will recover low voltage costs. Under IP's proposal, there will continue to be a separate demand charge to recover high voltage costs, which will be billed based on monthly maximum demands. (IP Ex. 6.6, p. 20) (IP Init. Br., p. 91)

(2) Staff's Position

Staff asks the Commission to reject IP's proposal to institute a distribution capacity charge that will be billed based on a demand ratchet. Staff believes that IP's proposal is problematic. Staff contends that while the 12-month ratchet magnifies the importance of the customer's peak as a signal to control demands, it diminishes the need to control monthly peak demands, which have no effect on the distribution capacity charge as long as they remain below the 12-month peak. Staff asserts that IP's claim that a lack of diversity for low voltage facilities justifies the 12-month ratchet does not withstand scrutiny. Staff argues that IP has presented no evidence that the customers who share common low voltage facilities will peak during the same hour, the same day or even the same month. Thus, Staff believes that customers who peak at different times of the year have less incentive to curb their demands at the time of local peaks under IP's proposed demand ratchet. (Staff Ex. 5.0, p. 31) Staff further contends that IP's proposal also conflicts with longstanding Commission policy against ratchets proposed by utilities. Staff cites Commonwealth Edison's 1999 DST Case (Docket No. 99-0117) as one in which the Commission rejected use of a demand ratchet, for reasons that Staff contends should apply in this case. (Staff Init. Br., pp. 60-61)

Staff takes issue with IP's argument that a demand ratchet would make delivery services rates consistent with bundled rates. Staff contends that IP's concern about consistency is undermined by its failure to implement a demand ratchet in the 1999 DST Case. Staff also notes that IP's current bundled rates were approved almost a decade ago. Staff states that since then, the Commission has clearly voiced its opposition to demand ratchets and IP's bundled rates clearly conflict with this position. Staff argues that instead of extending a flawed rate design to delivery services, the proper course is to reject the demand ratchets associated with distribution capacity charges in this case and then take advantage of the next opportunity to remove demand ratchets for bundled customers. (Staff Ex. 5.0, p. 33) (Staff Init. Br., pp. 61-62)

Staff disagrees with a hypothetical example presented by IP witness Jones of two customers with the same annual peak demand but different load factors. According to Mr. Jones, the two customers would require the same distribution investments to serve the maximum loads but the higher load factor customer would pay more in monthly demand charges. Staff claims that Mr. Jones' example rests on the faulty premise that the only demands that matter from a distribution standpoint are annual peak demands of individual customers. Staff believes that this argument fails to consider the benefits of demand diversity. Staff asserts that this potential benefit may not exist for a high load factor customer with a constant distribution demand. Thus, Staff contends, it is incorrect to assume that these two customers are responsible for equal distribution investments by IP. (Staff Ex. 14.0, p. 25) (Staff Init. Br., p. 62)

(3) IIEC's Position

IIEC supports an equal percentage increase in the facilities charges, metering charges and demand charges for the demand-metered class, for the reasons stated in Section III.A.1.b of this Order. (IIEC Init. Br., p. 15) The Commission notes that because IP's proposed distribution capacity charge is only applicable to customers served at delivery voltages of 12.47 kV and below, it would probably not be applicable to most if not all of the IIEC companies in this case, who are large-volume, high-voltage users.

(4) Commission's Analysis and Conclusion

Based on its review of the record, the Commission concludes that IP's proposal to establish a separate distribution capacity charge for customers in the demand-metered class taking service at 12.47 kV and below, to be billed on the basis of the customer's highest demand in the preceding 12 months is reasonable and should be approved. The Commission finds that the record supports breaking the current demand charge for these customers into a distribution capacity charge, to recover the cost of lower-voltage, more local facilities, and a demand charge to recover the cost of higher voltage facilities. The demand charge will continue to be billed on the basis of the customer's maximum demand in each month. The record shows that the cost of service bases underlying each charge supports the differing methods of billing the two charges. In addition, the Commission believes that establishing the separate distribution capacity charge will help to reduce the possibility of rate disparities and subsidies among the customers in the demand-metered class.

The Commission does not accept Staff's arguments in opposition to the adoption of the distribution capacity charge and to the use of the demand ratchet. The Commission acknowledges that in certain recent cases it has rejected the use of demand ratchets, but notes that in those cases, the utility was seeking to recover its entire revenue requirement from a particular class using a rate that would be billed based on a 12-month demand ratchet. Here, under IP's proposal, the demand ratchet would only be used for billing one charge that is applicable to a segment of the demand-metered class, and is not the only charge to these customers. The Commission agrees with IP's reasoning that under its overall rate design, including continuation of a demand charge billed on the basis of maximum monthly demands, the customers will still have adequate incentives to control their maximum demands. Finally, the Commission concludes that adoption of the distribution capacity charge that mirrors the charge in IP's bundled rates for demand-metered customers is appropriate on rate continuity grounds.

c. Reactive Demand Charges

IP proposed to increase the reactive demand charge to 20 cents per kvar. (IP Ex. 6.6, p. 15) Staff witness Lazare proposed a slight increase above the current charge of 10 cents per kvar. (Staff Ex. 14.0, Sched. 14.5, p. 3) IIEC proposed that the reactive demand charge either be kept at the current level, or increased by an equal percentage to all other charges. (IIEC Ex. 1, p. 21; IIEC Ex. 6, p. 16) However, the parties ultimately agreed that for purposes of this proceeding, the reactive demand charge should be set at 13.0 cents per kvar. (Tr. 804-05 (Jones, IP); Staff Ex. 22.0 (Lazare, Staff); Tr. 687-88 (Stephens, IIEC)) (IP Init. Br., p. 91) The Commission concludes, based on the record, that setting the reactive demand charge at 13.0 cents per kvar as agreed by the parties interested in this issue, is reasonable and should be approved.

d. Transformation Charges

(1) IP's Position

SC 110 currently includes transformation charges of 50 cents per kW of distribution capacity for customers with distribution capacities below 3 MW, and 75 cents per kW for customers with distribution capacities of 3 MW or more. IP is not proposing any changes to the transformation charges in this case. IP opposes IIEC proposal that the transformation charge for customers 3 MW and above be re-set to the same level as the charge for customers below 3 MW, 50 cents per kW, or alternatively, that the transformation charge for all customers be set at 75 cents per kW. IP also notes that Staff witness Lazare proposed maintaining a differential similar to that in current SC 110 between the transformation charges for customers below 3 MW and those 3 MW and above; however, he proposed to revise the below-3 MW charge from 50 cents to 53.1 cents per kW, and to revise the above-3 MW charge from 75 cents to 79.7 cents per kW. (Staff Ex. 22.0, Sched. 14.5 Rev.) IP states that these small deviations from the current rates are apparently due to Mr. Lazare's proposed reductions in other charges and the resulting need to increase the transformation charges in order to recover the full class revenue requirement. (IP Init. Br., p. 92)

In responding to IIEC, IP explains that demand-metered customers have the option to either take transformation service from IP, or rent or install their own transformation facilities. Accordingly, IP based the transformation charge on the cost of installing new transformers, plus applicable expenses, to be consistent with the economic decision the customer faces. (IP Ex. 6.6,

p. 16; see IP Ex. 6.10, Sched. 2, item 4) IP also notes that transformation charge revenues serve to reduce the class revenue requirement that must be recovered through demand charges. (IP Ex. 6.6, p. 16) IP states that the charge of 75 cents per kW for customers 3 MW and larger is within the range of the costs of recently installed transformation facilities for customers of this size. (Id.; IP Ex. 6.10, Sched. 2, item 4) However, IP notes that, due to the fact that transformation facilities for customers over 3 MW often have to be tailored to meet the customer's particular requirements, these larger customers can usually obtain transformation on a more cost-effective basis by owning or renting their transformation facilities. IP notes that of 73 customers on its system larger than 3 MW, only 16 take the tariffed transformation service; the other 57 customers own or lease their transformation facilities. (IP Ex. 6.6, p. 16-17; IP Ex. 6.14, pp. 15-16) (IP Init. Br., pp. 92-93)

IP contends that IIEC's argument that the transformation charge must be based on embedded costs because "transformation service has not been declared competitive" (IIEC Init. Br., p. 16) is a red herring. IP states that if transformation service were "declared competitive" by the Commission pursuant to Section 16-113 of the PUA, IP would not be obligated to offer this service as a tariffed, regulated service at all, nor be constrained to any specific cost basis for its charges, embedded, marginal or other, but only by what the market would bear, if IP were to continue offering transformation service at all, which it would not be required to do. IP states that even though transformation service has not been "declared competitive", demand-metered customers have the option of obtaining their transformation requirements through installation of their own facilities, leasing facilities from IP or leasing facilities from a third party. Thus, basing the transformation charge on the current cost to IP to install transformation facilities for a customer reflects not only the economic decision the customer faces (IP Ex. 6.6, p. 16), but also the costs the customer imposes on IP if it decides to obtain tariffed transformation service from the Company. IP states that if it were required to provide tariffed transformation service to above-3 MW customers who elect to obtain that service from the Company, at a price below the cost of installing the required facilities, as IIEC suggests (and correspondingly, below the cost to the customer of obtaining the facilities from other sources), IP would have to recover the resulting revenue deficiency through other charges. As a result, other customers would be subsidizing the above-3 MW customer who elects to obtain the service from IP. (IP Ex.6.6, p. 17) IP states that this result would be inappropriate given that these customers have competitive options for transformation facilities and service.

In response to IIEC's contention that the cost information in IP Exhibit 6.10, Schedule 2, Item 4, does not support a 75 cent per kW transformation charge for customers 3 MW and above (IIEC Init. Br., pp. 16-18), IP states that IIEC has cited the original version of this schedule at page 18 of its Initial Brief, not the corrected version. IP states that the average of the cost per kW of the five recent transformation installations for customers 3 MW and above shown on Revised IP Exhibit 6.10, Schedule 2, Item 4 is 63 cents, not 55 cents. IP notes that the average cost per kW of transformation facilities for customers below 3 MW as shown on this schedule is 47 cents, consistent with the current transformation charge of 50 cents per kW for these customers. IP further states that by focusing on the average cost of the installations for the above-3 MW customers, which IP did not calculate on the schedule, IIEC is missing the point of the exhibit, which IP states is to show that a charge of 75 cents per kW is within the range of costs of recently installed facilities. (IP Ex. 6.6, p. 16) IP states that it is the range of costs of transformation installations for these larger customers, not the average, that is important, because of the differing facilities that different customers above 3 MW may require depending upon their particular service configuration. (Id., p. 17; IP Ex. 6.14, pp. 15-16) In response to IIEC's assertion that one of the five installations for customers 3 MW and above shown on this schedule was actually for a customer smaller than 3 MW, IP states that the installation IIEC is referring to was for a customer whose distribution capacity is 2.975 MW.

In response to IIEC's arguments that the embedded cost of transformation on the IP system is $1.12 per kW, and that in the 1999 DST Case, Mr. Jones testified that the embedded cost of transformation is 42 cents per kW (IIEC Init. Br., p. 18), IP states that the $1.12 per kW figure is the embedded cost of transformation throughout IP's entire system, including the cost of transformation equipment that transforms power from the transmission or subtransmission voltage all the way down to the service level required by the customer, including residential and small use general service customers. (IP Ex. 6.14, p. 16) IP states that this system-wide average figure is not really relevant to determining the cost of transformation needed to reduce power from the supply line voltage serving a 3 MW and above customer to the service voltage level that customer requires, which is the basis for the transformation charge. (Id., pp. 16-17) With respect to the 42 cents per kW figure cited from the 1999 DST Case, IP states that this figure was the embedded cost only for line transformers installed on the IP system, whereas the $1.12 per kW figure is the embedded cost of both line transformers and substations, and is the more appropriate representation of the cost of transformation on the IP system. IP states that in any event, neither of these system-wide cost figures is relevant to determining the appropriate charge for transformation specifically installed to serve demand-metered customers 3 MW and above.

Finally, IP notes that the transformation charge in IP's bundled rates is 75 cents per kW for both customers smaller than 3 MW and customers 3 MW and above. (IP Ex. 6.6, p. 16) Therefore, IP argues, if the Commission concludes that there should not be a different transformation charge in SC 110 for customers below and above 3 MW, the proper solution would be to set the transformation charge at 75 cents per kW for all demand-metered customers taking transformation service from the Company. IP believes that this would promote rate continuity as customers switch from bundled service to delivery services. (IP Init. Br., p. 93)

(2) IIEC's Position

IIEC argues that IP has failed to provide any cost justification for the disparity in treating customers greater than 3 MW differently than customers below 3 MW with respect to the transformation charges in SC 110. IIEC contends that there should be no different charge for customers above 3 MW as compared to customers below 3 MW, without a sound cost analysis, which IIEC contends has not been produced. IIEC asserts that IP has relied upon a marginal facilities cost approach in determining the level of the transformation charges, which justifies rejecting IP's charges. IIEC notes that IP is using an embedded revenue requirement and an embedded cost of service study for allocating costs in this case. (IIEC Ex. 1, p. 22). IIEC notes that IP's justification for using a marginal cost approach is that it reflects the economic decision customers face. IIEC maintains that transformation service has not been declared competitive for either bundled or delivery service, and hence, there is no basis to depart from embedded cost. IIEC notes that when pricing metering service, IP uses embedded cost even though metering is an unbundled service that may be provided by others. (IIEC Init. Br., p. 16)

IIEC contends that even assuming *arguendo* a marginal cost approach is appropriate, the evidence suggests lower transformation charges for larger customers are justified. IIEC states that according to information provided by IP intending to depict a representative sample of recently constructed substations for customers over 3 MW, three out of the five sample installations are below 50¢ per kW, and the only sample significantly above 50¢ per kW is associated with a transformer that is actually less than 3 MW in size. IIEC contends that the average transformation charge based on this information suggests a 50¢ per kW charge or lower for customers greater than 3 MW, rather than the 75¢ per kW charge. (IIEC Init. Br., p. 16)

IIEC notes that IP witness Voiles argued that the Commission required larger customers to rent or own their transformation equipment, rather than imposing a fixed charge in the tariff because the cost of transformation equipment for larger customers varies considerably based on the circumstances of each customer. IIEC contends that a review of the Commission's 1999 DST Order reveals nothing of the sort as stated by Ms. Voiles; according to IIEC, all the Commission did was to approve IP's proposed 50¢ per kW transformation charge for delivery service customers with essentially no discussion, since the issue was uncontested in that case. Further, IIEC argues, IP, when setting the 50¢ per kW charge for customers with less than 3 MW of demand, ignored the fact that the bundled transformation charge for all customers is 75¢ per kW. IIEC also notes that Ms. Voiles claimed that only upon request by an above 3 MW customer did IP decide to offer the option of transformation service based on a tariff charge for these customers in SC 110, similar to the charge paid by customers under its bundled tariff. Yet, IIEC argues, Ms. Voiles ignored the fact that this customer rejected IP's offer to pay a charge that is 50% higher than the customer less than 3 MW. (IIEC Init. Br., p. 17)

IIEC also notes that in a data request response, IP indicated the embedded cost of transformation on the IP system is not 50¢ per kW or 75¢ per kW, but instead $1.12 per kW. IIEC disagrees with IP witness Jones' testimony that one would expect the embedded and marginal cost of transformation to be reasonably close to one another. (Tr. 886-87). IIEC contends that the evidence in this case indicates that the marginal costs of transformation is approximately 50¢ per kW and the embedded cost is $1.12 per kW. IIEC also notes that Mr. Jones testified in the 1999 DST Case that the embedded cost of transformation on the IP system was only 42¢ per kW. (IIEC Init. Br., p. 18)

In conclusion, IIEC submits that IP has not justified a different level of transformation charges for customers below 3 MWs as compared to above 3 MW. IIEC contends that all customers should be charged either 50¢ per kW, or all customers should be charged 75¢ per kW. IIEC submits that there is no basis for a different charge for each group of customers. IIEC states that continuity with the bundled service tariffs would favor a 75¢ per kW transformation charge for all delivery service customers. (IIEC Init. Br., p. 18)

(3) Commission's Analysis and Conclusion

Based on its review of the record, the Commission concludes that the transformation charges in SC 110 should be left at their current levels, i.e., 50 cents per kW of distribution capacity for customers with distribution capacities below 3 MW, and 75 cents per kW of distribution capacity for customers with distribution capacities of 3 MW and above. The Commission notes that since IP has not proposed any change to these charges in its tariff filing in this case, it would be inappropriate to increase the charge to customers with distribution capacities below 3 MW, even if the Commission were to find that such an action were otherwise justified. The Commission concludes that the cost information provided by IP on Revised IP Exhibit 6.10, Schedule 2, Item 4 supports the charge of 75 cents per kW to customers 3 MW and above. The Commission rejects IIEC's argument that basing the transformation charge on the current cost to install transformation facilities for a customer is precluded by the fact that transformation service has not been declared "competitive" under Section 16-113 of the PUA. The fact is that demand-metered customers have the ability to own or lease their own transformation facilities rather than taking the tariffed service from IP. In light of this fact, the Commission believes that the transformation service needs to be kept at 75 cents per kW for customers above 3 MW. Reducing this charge would necessitate that other demand charges, for which the customers in this class do not have competitive options, would have to be increased to make up for the revenue differential. The Commission finds that this would be inappropriate.

e. Standby Capacity Requirement for Self-Generation Customers Using Delivery Services for Standby Purposes

(1) IP's Position

An IP customer that installs self-generation ("SG") facilities at its premises to serve all or a part of the customer's electrical load may elect to contract with a RES to provide power and energy for standby or back-up purposes during periods when the customer's SG facilities are not operating (or operating at a reduced level). Such a customer would need to use IP's delivery services to deliver standby or backup power from the RES when the customer's SG facilities are not operating. At the time the SG customer needs to use standby power from its RES, the customer will be placing onto IP's grid all or a significant part of its load that is normally served by the customer's SG facility. (Tr. 912-13) IP states that although the customer has installed a SG facility, IP's grid still needs to be capable of serving the customer's entire load from time to time, on no notice, whether the SG customer places its entire load on the grid frequently or infrequently. Thus, IP states, IP's investment in distribution facilities in order to be prepared to serve both SG and (comparably-sized) non-SG customers is the same. IP notes, for example, that substations and transformers serving the customer must be sized to serve the customer's maximum expected demand at any single moment. (IP Ex. 6.6, pp. 24-25; IP Ex. 6.14, p. 25; Tr. 914, 933-34) (IP Init. Br., pp. 93-94)

IP proposes to require customers with SG facilities that wish to use delivery services for back-up or standby supply purposes to establish a standby capacity requirement ("SCR"). The SCR would be used to bill the SG customer's demand charge, distribution capacity charge (if applicable to the customer) and transformation charge (if applicable to the customer) under SC 110. (IP notes that the proposed distribution capacity charge is only applicable to delivery services customers served at a supply line voltage of 12.47 kV or lower; therefore, if a SG customer is served at a supply line voltage above 12.47 kV, the distribution capacity charge will not apply. Similarly, the transformation charge is only applicable to demand-metered customers for whom IP owns and operates transformers to transform voltage from IP's available supply line voltage to the delivery-voltage at which the customer takes service, so if a SG customer owns or leases its transformation, the transformation charge does not apply to that customer.) However, for those charges that are billed to non-SG customers on the basis of maximum monthly demands (i.e., demand charges), IP will apply a load diversity factor to the SG customer's SCR to adjust the SCR to approximate a monthly maximum demand. The load diversity factors will be taken from the load profiles used for purposes of Rider TC, and will be in the range of 75% to 85%, depending on the SG customer's size and its load factor if its self-generation were idle for a year. (IP Ex. 6.6, pp. 22-24) (IP Init. Br., p. 94)

Initially, the customer will specify its SCR; IP will not modify the SCR specified by the customer. However, if the customer's maximum demand subsequently exceeds the SCR, a new SCR will be established at the customer's new, actual demand level. After 12 months, assuming the SCR has not been exceeded, IP will review the customer's demands and connected loads to determine if the customer's SCR should be reduced. (IP Ex. 6.6, p. 21) In addition, if the SG customer's maximum demand in a month exceeds its current SCR by more than 10%, the customer will be billed three times the applicable charges that are billed based on SCR, times the incremental maximum demand for the month in excess of 110% of the customer's current SCR. (IP Ex. 6.6, p. 21; IP Ex. 6.14, p. 17) (IP Init. Br., p. 95)

IP responded to the objections of IIEC witness Stephens and Staff witness Haas to the proposed SCR provision. IP noted that several aspects of its SCR proposal were added or modified in rebuttal in response to criticisms expressed in Messrs. Stephens' and Haas' direct testimonies. IP contends that Staff's and IIEC's remaining objections to do not justify rejecting the SCR proposal. (IP Init. Br., p. 95)

IP disputes IIEC's and Staff's contention that the SCR provision results in SG customers being treated differently from non-SG customers with no basis for such treatment. IP states that for those charges that are billed to non-SG customers based on the customer's maximum demand in the prior 12 months (i.e., the distribution capacity charge and the transformation charge, if these charges are applicable to the customer), the SCR requirement is likely to produce similar results as would occur if the SG customer's generating facility went down once per year at a time when the customer's load was high. That is, the customer's SCR and its distribution capacity (the basis used to bill distribution capacity charges and transformation charges to non-SG customers) are likely to be similar. Further, under its proposal, IP will review the SG customer's SCR every 12 months to determine if it should be lowered. (IP Ex. 6.1, p. 20; IP Ex. 6.6, pp. 21-22) With respect to the demand charge, which is billed on the basis of maximum monthly demands, the application of the load diversity factor to the SG customer's SCR will result in a billing determinant that approximates the customer's maximum monthly demand if its generation were idle, resulting in the SG customer being billed in a manner consistent with non-SG customers. (IP Ex. 6.6, p. 23) IP contends, however, that SG customers and non-SG customers are in fact different. IP states that both types of customers are receiving the same service from IP, no-notice access to the delivery system for the customer's entire load, but the SG customer using delivery services for standby purposes is asking IP to stand ready to serve the customer's entire load that is served by the SG facility, yet the customer may place this entire load (or any substantial part thereof) on SC 110 only occasionally. IP states that as a result, if the SG customer were billed under SC 110 only based on its actual monthly demands, it would not pay for the cost of this service. IP notes that for Illinois utilities, demand charges are set so as to recover the annual demand cost through a charge that is assessed on a monthly basis. Thus, if an SG customer is only billed a demand charge in some but not all months of the year, the annual demand cost to serve the customer would not be recovered from that customer This would necessitate higher charges to non-SG customers to recover the total class cost of service, i.e., other customers would be subsidizing the SG customers. (IP Ex. 6.1, p. 20; IP Ex. 6.6, pp. 22, 25-26) IP contrasts this with the non-SG customer who can be expected to have much more consistent demands on IP's system each month (IP Ex. 6.14, p. 21); therefore, IP concludes, use of the non-SG customer's actual monthly and annual (prior 12 months) maximum demands will result in proper cost recovery. (IP Init. Br., pp. 96-97)

With respect to the contention that the provision whereby a SG customer is billed three times the applicable demand charges for incremental demands in excess of 110% of the customer's SCR is not cost-based, IP states that it is not intended to be cost-based. Rather, IP states, it is intended to discourage the SG customer from underestimating its standby capacity requirement and thereby avoiding paying for its full cost of service. IP states that this provision is intended to give the SG customer an incentive to accurately estimate and contract for the level of delivery services that the customer requires IP to be ready to provide on no notice. (IP Ex. 6.14, pp. 18-19) Moreover, IP notes, such tariff provisions that are applicable in the event of a customer exceeding a stated contract amount are not new. For example, IP's gas tariffs for demand metered customers (SC 65 and 76) contain a provision to charge customers an Excess MDQ Charge of three times the demand charge for the excess demand over a stated Maximum Daily Quantity. Similarly, IP's gas transportation tariffs (and those of other Illinois gas distribution companies) impose charges of $6 per therm if the customer takes unauthorized overrun gas. (IP Ex. 6.14, p. 19) (IP Init. Br., pp. 97-98)

IP disputes Staff's contention that the triple demand charge billing for exceeding the customer's SCR will provide an incentive for the SG customer to over-estimate its SCR. IP states that a customer sophisticated enough to have acquired, installed and be operating SG facilities sized to serve all or part of the load at its premises, and to have arranged for standby generation service from a RES, can be expected to have an accurate estimate of the load that is served by its SG facilities, and the amount of load that would be switched to the customer's standby source, and therefore to IP's delivery system, if the SG facility were not operating. (See Tr. 879-81, 916-17) IP notes that IIEC has pointed out that an SG customer who signs a contract with a RES for a certain amount of standby electric generation capacity can be expected to specify sufficient standby delivery services capacity to match its standby supply contract. IP states that IIEC's argument shows that the SG customer should have little difficulty in accurately specifying its SCR, and little risk of exceeding the SCR it has specified. Further, IP's proposed SCR provision gives the customer a 10% margin of error before the triple demand charges apply. (IP Ex. 6.6, p. 21) IP also notes that for these reasons, there is no need to adopt IIEC's proposal that SG customers should contract with IP for specified amounts of standby capacity, which could necessitate contract negotiations and would impose administrative costs on IP and the customer. IP reiterates that it will accept the SG customer's initial specification of its SCR. (IP Init. Br., pp. 98-99)

With respect to Staff's contention that the SCR provision does not recognize the load diversity of SG customers on IP's system, IP responds that, at present, it has only 9 SG customers on the almost 800 circuits in its system, and no two of those SG customers are served on the same circuit. Therefore, these SG customers do not provide any load diversity benefits. IP states that the level of investment in distribution facilities to provide, or stand ready to provide on no notice, delivery service to these SG customers is the same as it is for non-SG customers.

Indeed, IP argues, it would be irresponsible for IP to assume that an SG customer's SG facility will always be running at the time of the peak demand on the circuit that serves the customer; to do so would risk a degradation in reliability. (IP Ex. 6.6, pp. 24-25; IP Ex. 6.14, p. 20) IP points out that Staff witness Haas acknowledged that IP's grid needs to continue to be capable of serving the customer's entire load, and that IP cannot reduce the load-carrying capability of the circuit that serves the SG customer by the amount of the capacity of the customer's SG facility. (Tr. 913-14) (IP Init. Br., pp. 98-99)

With respect to Staff's contention that the SCR provision will discourage the installation of cost-effective self-generation, IP reiterates that a customer sufficiently sophisticated to have designed and installed, and be operating an SG facility to serve all or part of its load should be capable of accurately estimating its SCR, particularly in light of the 10% cushion before the triple demand charges apply. Moreover, IP contends that it is extremely unlikely that either the need to pay demand, distribution capacity and transformation charges (the latter two charges if applicable to the customer) based on the SCR under IP's proposal, or the threat of occasionally having to pay the triple demand charges, will adversely impact a customer's decision to install and use SG facilities. IP states that the customer's investment in the SG facility, the cost of fuel and other operating costs for the SG facility, and the market price of power the customer may have to pay to its third party supplier for standby power if its SG facility is out of service, will far outweigh IP's delivery services charges in the customer's economic calculations. (IP Ex. 6.14, p. 21) IP points out that this is confirmed in IIEC's Initial Brief, where IIEC shows that the cost of standby delivery capacity will range from 2 cents to 40 cents per kW, whereas the cost of standby generation capacity will be several dollars per kW. IP notes that Staff provided no quantitative analysis or examples to attempt to support its assertion that the costs to the customer under IP's SCR proposal will be sufficient to discourage customers from installing cost-effective self-generation. (IP Init. Br., pp. 98-99)

(2) Staff's Position

Staff contends IP's SCR proposal, even though somewhat improved by the modifications made by IP in its rebuttal testimony, will result in discriminatory treatment of SG customers relative to non-SG customers within the same delivery services class. Staff states that under IP's proposal the total distribution and delivery charges faced by non-SG customers will vary by month, based on their actual monthly usage levels, assuming the Commission also accepts Staff's proposal to reject the proposed distribution capacity charge that would be billed on the basis of a 12-month demand ratchet. Staff asserts that those non-SG DST customers with wildly varying monthly loads will potentially see significant changes in their distribution and delivery charges on a monthly basis, and will be encouraged to keep demand down, whereas SG customers will be charged every month as though their self-generation units never run and their monthly demand is constant at its potential peak level. Staff contends that this could result in distorted price signals in the deregulated market place. Staff also argues that IP's proposed SCR tariff provisions would penalize, and not reward, self-generation for the system benefits they can provide. Staff states that such benefits could include increased T&D capacity which would open the market to more sources of competitive generation, as well as improved system reliability through reduced system strain and the reduction of potential brown outs. Self-generation, Staff asserts, would also allow a measure of demand response to market conditions, further improving market conditions in times of tight demand relative to the case where demand is unable to respond to prices in the market. Other system benefits of prolific self-generation, Staff contends, are potential decreases in maintenance costs and system-wide costs associated with system upgrades. Staff also states that customer-specific benefits of increased self-generation include improved reliability and the ability to remove one's demand from a potentially volatile market for electricity. (Staff Ex. 8.0, pp. 7, 16) Staff witness Haas argued that the Company's proposal will make SG more costly than it should be relative to other competitive supply and load management alternatives. (Staff Ex. 8.0, p. 7) Staff argues that by making SG more costly than alternatives, the Company's proposal will assure that very little new SG is installed so that there will never be enough SG in place to make the coincident peak/diversified load model relevant. It is Staff's position that IP's proposal would also work to prevent the very real benefits of SG generation from being realized in the long run. (Staff Init. Br., pp. 64-67)

Staff's recommendation is that discriminatory treatment of SG should be eliminated from the DST so as to provide a level playing field among the various load management technologies and competitive service options available to customers in the deregulated market. (Staff Ex.18.0, p. 3) It is Staff's position that SG customers should be charged on the same billing determinants and basis as non-SG customers. Staff states that this recommendation would require that the proposed language in 6.C(3), (4), (5) and 6.G(1), (2) and (3) of SC 110 regarding standby customers and charges be eliminated. In particular, Staff identifies SC 110, Section 6.G as the source of the discriminatory treatment of SG customers. However, in the event IP's proposal to use a demand ratchet in billing certain charges remains, Staff believes that the removal of SC 110, Section 6G and its related language will help to insure non-discriminatory treatment of SG customers relative to non-SG customers. In contrast, in the event that ratchets are removed from consideration due to Staff's arguments on other issues (i.e., with respect to the proposed distribution capacity charge for demand-metered customers taking service at 12.47 kV or below), Staff believes the removal of SC 110, Section 6.G and its related language from the Company's DST will insure non-discriminatory treatment of SG customers relative to non-SG customers. Further, Staff argues that at the very least, proposed Section 6.G(3) of SC 110, which states that "the Customer will pay (the) Utility an amount equal to three time the applicable demand charges described in Section 6.C.(3), (4), and (5) of this SC 110 for the (demand in excess of 10%) over the Customer's standby capacity" should be removed. (Staff Init. Br., pp. 67-68)

Staff claims that undistorted economic availability of SG requires the equitable treatment of SG customers, relative to non-SG customers, within the cost allocation mechanisms used by the Company. Accordingly, it is Staff's position that if all other non-residential customers on delivery services are charged, based on their actual usage and/or peak non-coincident demand, for power drawn across IP's distribution system, so should SG customers on delivery services. (Staff Ex. 18, p. 14) Staff argues that if IP's proposal for the treatment of SG customers were approved, it would over collect charges from SG customers relative to non-SG customers with the same level of actual system non-coincident peak demand within a 12-month period. (Staff Ex 18, p. 3) Staff states that non-SG customers do not have to pre-set their potential peak demand, nor do they have to pay every month on the basis of such an estimate. Nor must non-SG customers face triple charges for any demand they incur in excess of their pre-set potential peak. Staff claims that it is, therefore, inappropriate to require SG customers to set and pay charges based on a pre-determined level for their peak demand. (Staff Ex. 18, p. 4) (Staff Init. Br., pp. 69-70)

Staff also contends that as a result of IP's proposal, two SG customers with identical annual peak needs, but with SG units of differing reliability, will be charged the same amount of Demand Charges, regardless of the relative reliability of their units. Based on actual non-coincident peak demand on the IP's system, the basis by which all non-SG customers are charged, Staff contends that the more reliable SG customer will be paying a much higher effective rate per unit of actual non-coincident demand, and therefore subsidizing the less reliable SG customer. Staff argues that this problem is not mitigated by IP's proposed mitigation factor because it is not sensitive to the load profile of the customer with the SG unit in operation. Therefore, Staff contends, IP's proposal discourages use of more reliable SG units. (Staff Ex. 18, pp. 8-9) Staff further argues that IP's proposal in Section 6.G(3) of SC 110 will provide discriminatory rate treatment of SG customers relative to non-SG customers with identical annual peak, particularly for SG customers with reliable units. (Staff Ex. 18, p. 8) Staff concludes that these characteristics of Section 6.G(3) provide discriminatory treatment of SG customers vis-à-vis non-SG customers in terms of effective demand rates. (Staff Init. Br., pp. 72-73)

Staff argues that if IP's proposal for a distribution capacity charge is not rejected, then this charge should be collected monthly on the basis of monthly non-coincident peak demand. Staff states that in either event, to make the treatment of SG customers non-discriminatory, non-distortionary, and consistent, relative to the DST rate treatment of non-SG customers, it will be necessary to use the same method of calculation and collection for both SG and non-SG customers regardless of whether or not Distribution Charges are a separate tariff item or they are subsumed into the Demand Charges. (ICC Staff Ex. 18, p. 19) (Staff Init. Br., pp. 79-80)

Staff notes that Staff and IP have agreed to base transformation charges to non-SG customers on the 12-month peak demand. While Staff agrees that transformation charges to non-SG customers should be based on a 12-month peak demand, Staff argues that in order to make the treatment of SG customers non-discriminatory, non-distortionary, and consistent relative to the DST rate treatment of non-SG customers, it will be necessary to use the same method of calculation and collection for both SG and non-SG customers, by SG customers on DST service having their transformation charges accrued on the basis of their 12-month peak demand. Staff suggests that there would be several advantages to using the same methodology across all classes of customers regardless of whether or not they use SG. First, Staff believes that consistent treatment within the rate classes will eliminate the distorted prices signals that the Staff contends IP's proposal will send to the competitive marketplace regarding choices. (Staff Ex. 18, p. 13) Second, Staff believes that while the use of a 12-month actual peak demand will reduce the differentiation amongst customers that reduce their demand during the year, there will still be a weak incentive for both SG and non-SG customers to reduce their non-coincident peak demand. (Staff Ex. 18, p. 16) According to Staff, there will also be an incentive for SG customers to install more reliable units in order to lower their demand in the long run. Staff contends that this same incentive, no matter how weak, does not exist when charges are based on a standby value. (Staff Init. Br., pp. 84-86)

Staff also argues that the triple demand charge billing on excess demand, even with the 10% margin for error in IP's proposal, creates too strong an incentive for an SG customer to over estimate its SCR. Staff claims that given the possibility that its SG unit could fail, or its demand could spike by an unusual amount, an SG customer would have a strong incentive to overestimate its SCR in order to limit the exposure to the triple charges on the excess demand. Since, according to Staff, SG customers will have the incentive to over-subscribe for standby service, they will be overpaying relative to non-SG customer based on both the same actual and expected maximum demand. (Staff Ex. 18, pp. 4-5) Staff contends the existence of the triple charges provision exacerbates the situation with regard to the discriminatory treatment provided by the language in proposed 6.C(3), (4), (5) and 6.G(1), (2) and (3) of SC 110 regarding standby customers and standby-based demand and distribution capacity charges. (Staff Init. Br., pp. 87-88)

Staff summarizes its position by stating that it recommends that the language in 6.C (3), (4), (5) and 6.G (1), (2) and (3) of SC 110 regarding standby customers and standby-based charges, as currently presented, be removed from SC 110 because, in Staff's opinion, it provides an uneconomic and distortionary price signal to customers with or considering SG, relative to other options and customers in the Company's proposed DST tariff. Staff suggests that a more appropriate treatment of self-generation would have the Company providing incentives for self-generation, through special contracts or other measures, when and where on-site generation could provide system benefits. This would be particularly important, Staff argues, given IP's statement regarding difficulties it foresees with maintaining reliability. (Staff Ex. 8, p. 8) Staff further states that if the Commission does not wish to completely remove this language, Staff recommends substituting language that would provide as consistent a treatment between SG and non-SG customers as possible. Staff believes that any mechanism used should provide similar, if not the same, price signals to all customers. Staff further recommends that the Commission also pursue the goal of providing inherent incentives to all customers shave peak demand. Staff has proposed a number of alternatives to IP's proposal which would provide equity and price signals more in line with the policy goals outlined above. (Staff Init. Br., pp. 88-89)

Specifically, Staff's first alternative (second choice) to completely removing the language in 6.C (3), (4), (5) and 6.G (1), (2) and (3) of SC 110 regarding standby customers and standby based charges is to use each SG customer's rolling 12-month average of its monthly non-coincident peak demand, instead of Standby Capacity, as the basis for the determination of monthly demand and distribution capacity charges. (Staff Ex. 18, p. 15) Staff suggests that this would allow some differentiation between SG customers that are better at reducing their non-coincident peak demand through the use of more reliable SG units and/or more aggressive load-shedding. This would provide an incentive to both install more reliable units and reduce overall demand. Staff argues that while this will still treat SG customers in a discriminatory fashion relative to non-SG customers, this would be less distortionary in its signals than the IP's proposed standby-based DST charges. (Staff Ex. 18, p. 15) Staff's second alternative (third choice) is to use billing determinants based on each SG customer's 12-month maximum demand, instead of standby capacity, as the basis for the determination of monthly demand and distribution capacity charges. Staff states that while this would only allow some minor differentiation between SG customers that are better at reducing their non-coincident peak demand through the use of more reliable SG units and/or more aggressive load-shedding, Staff believes that it provides a slight incentive, relative to IP's proposal, to both install more reliable units and reduce overall demand. Staff contends, however, that this methodology will tend to overcharge SG customers relative to non-SG customers. To mitigate this overcharging, Staff recommends using a form of "Load Diversity Factor" to adjust the customer's 12-month maximum demand to approximate a monthly maximum demand. Staff strongly recommends a

"Load Diversity Factor" that would be correlated with the performance of the customer's SG unit as a means of shaving peak. Staff suggests that an example of such a "Load Diversity Factor" would be to subtract, on a monthly basis, the demand registered by the customer's SG unit meter at the time of the customer's greatest total peak for the month, as measured by the highest sum of the demand registered on the customer's SG unit meter and the Company's meter. (ICC Staff Ex. 18, p. 16) Staff's third alternative (fourth and least desirable choice) is to use the customer's contracted standby capacity, but apply a "Load Diversity Factor" that would be correlated with the performance of the customer's SG unit as a means of shaving peak. Staff suggests that an example of such a "Load Diversity Factor" would be to subtract, on a monthly basis, the demand registered by the customer's SG unit meter at the time of the customer's greatest total peak for the month, as measured by the highest sum of the demand registered on the Customer's SG unit meter and the Company's meter. (Staff Ex. 18, p. 16) (Staff Init. Br., pp. 88-91)

(3) IIEC's Position

IIEC does not object to IP's proposal that SG customers using delivery services for standby purposes would be required to enter into a contract for standby delivery capacity. However, IIEC objects to the ratchet provision and the triple charge provision relating to demands in excess of 110% of the SG customer's SCR, as IP has proposed. (IIEC Init. Br., p. 21)

IIEC asserts that IP misunderstands the nature of standby service. IIEC states that standby delivery service reserves capacity on the delivery facilities used to deliver generation from a third party supplier, in the event a customer's own SG fails or is temporarily unable to generate the customer's electric power needs. In a standby delivery service arrangement, a customer would contract with a RES for standby generation capacity. IIEC asserts that if a customer were to contract for 10 MW of standby generation capacity from a RES, it would make no sense not to contract for a commensurate amount of standby delivery capacity to deliver the power in those events when it is needed. IIEC notes that standby generation capacity is likely to be more costly than standby delivery capacity. Using IP's SC 22 standby rate as an example, IIEC concludes that the charge for standby generation capacity is likely to be on the order of dollars per kW of standby generation capacity, while the cost of standby delivery capacity, even under IP's proposed rates, for large customers is likely to range from about 2¢ to 40¢ per kW. IIEC argues that it would be illogical for a customer to contract for 10 MW of relatively expensive standby generation capacity (at dollars per kW) and skimp on the amount of delivery capacity it reserves (cents per kW). IIEC states that concerns IP may have about a customer under-contracting for standby delivery capacity are not valid when considering the nature and relative cost of standby delivery capacity in comparison to the cost of standby generation capacity. (IIEC Init. Br., p. 22)

IIEC believes that IP's proposal is discriminatory and unfair, resulting in disparate treatment between standby customers and other delivery service customers. IIEC states that the disparate treatment occurs when a non-SG customer is billed for delivery service based on a non-ratcheted demand, while the SG customer is billed based on a ratcheted demand. In this instance, IIEC contends, the SG customer pays more for the same facilities and use than would the non-SG customer. (IIEC Ex. 1, p. 18) (IIEC Init. Br., pp. 22-23)

IIEC also takes issue with the three times charges for demand in excess of the SCR as being unnecessarily punitive. First, IIEC contends that non-SG customers are not penalized for abnormally high demands; a bundled service customer that does not have generation but whose demands exceed any level of demand it may have taken in the past 12 months is not subject to additional charges of any kind. In addition, IIEC argues, the treble damages are not necessary because standby customers already have the necessary incentive by which to ensure they have contracted for the correct amount of standby delivery capacity. A customer that has generation, and is in obvious need of standby generation, would expect to contract for the proper level of standby delivery service in the event its generation fails. (IIEC Init. Br., pp. 23-24)

IIEC proposes that IP and the SG customer enter into a contract for standby capacity based on agreed levels of standby delivery capacity. IIEC states that the level of standby capacity and the term of the agreement would be based on the capacity and operating characteristics of the customer's load and generating units. IIEC finds no reason to believe that it would be problematic in setting an appropriate level of contract delivery capacity and claims that IP did not come forward with any arguments or reasoning to suggest otherwise. IIEC questions why IP would believe that the parties may not be able to agree to a level of standby capacity. IIEC states that if agreement is not reached, the customer would have recourse to the Commission. During the time the complaint is pending, IIEC states, the customer could pay whatever it was being charged on the basis of IP's estimate of the required standby capacity, just like any other customer that has a billing dispute or claims it is being overcharged for service. (83 Ill. Adm. Code 280.150) (IIEC Init. Br., p. 24)

IIEC agrees with IP's proposal to use diversity factors to convert the customer's standby capacity to a billing determinant, as being more representative of the monthly maximum demand. (IIEC Ex. 4, p. 15) (IIEC Init. Br., p. 24)

(5) Commission's Analysis and Conclusion

Based on its review of the record and of the arguments of the parties, the Commission concludes that IP's proposed tariff provisions relating to the standby capacity requirement for SG customers, as modified by IP in its rebuttal testimony as summarized earlier in this Order, are reasonable and should be approved. Initially, the Commission notes that the SG customer using delivery services for standby or backup purposes is receiving the service from IP of no-notice access to the delivery system for the customer's entire standby requirement. IP is required to maintain sufficient delivery capacity to serve the SG customer's entire standby load on no notice, even though the SG customer may go many, many months without utilizing this service. Since this Commission sets demand-related charges to recover an annual revenue requirement through monthly charges, it is necessary to implement a method of billing SG customers that fully recovers the costs to serve them. Otherwise, other customers will be subsidizing the SG customer. The Commission notes that the issue with respect to the SG customer and the SCR provision is not whether IP's revenue requirement needs to be increased due to SG customers, but rather how to equitably recover the total demand-metered class revenue requirement from SG customers and all other customers in this class. The Commission concludes that IP's modified SCR provisions meet this objective.

The Commission also finds that there are sufficient differences between SG customers and non-SG customers to warrant applying the SCR provisions to SG customers. While it is possible to conceive of isolated or relatively extreme examples of non-SG customers that have fairly erratic demands from month-to-month, most SG customers will have fairly consistent demands from month to month. Therefore, the non-SG customer's monthly demand, in general, will tend to be fairly representative of the maximum demands the customer places on the system, and will provide a billing determinant that enables the utility to recover the annual cost of service through a monthly charge. This is not the case, in contrast, if one were to use the SG customer's actual monthly demands as the basis for billing demand charges. With respect to those charges (if applicable to the customer) that would be billed to non-SG customers on the basis of the maximum demand in the prior 12 months, the Commission concludes that there is likely to be little difference between the non-SG customer's annual maximum demand and the SG customers SCR. These measures provide appropriate bases for billing transformation charges and distribution capacity charges to these respective customers, and are not discriminatory.

The Commission does not agree with Staff that the SCR provisions are likely to give the SG customer an incentive to over-estimate its SCR. The Commission agrees with IIEC as well as with IP that the SG customer should be able to estimate it actual SCR with a high degree of accuracy, i.e., by specifying a SCR that matches its standby generation contract. Further, the 10% deadband provision that IP added to its proposal in rebuttal provides a reasonable margin for estimating error by the customer. Finally on this point, the Commission does not find the triple charges provision to be any less appropriate than excess MDQ charges or charges for unauthorized overrun gas that the Commission has approved in local gas distribution company tariffs. The Commission has recognized the legitimate purpose of such provisions to discourage customers from underestimating their actual requirements in order to avoid paying their fair share of total system costs.

The Commission does not agree with Staff's arguments that the SCR provisions will discourage cost-effective self-generation on the IP system. The Commission agrees with the evidence presented by IIEC, as well as by IP, that the incremental charges to an SG customer resulting from IP's proposal are so small in relation to the total, other costs of owning and operating SG facilities, including the costs of acquiring backup generation capacity, that it is extremely unlikely that the presence of IP's provisions could tip the economics for an SG installation from favorable to unfavorable. While the Commission does not disagree in the abstract with the potential benefits to the system of installation of greater amounts of SG, as described by Staff, the Commission does not find that IP's SCR provisions will result in any noticeable adverse impacts on the economics of SG for customers on the IP system. The Commission notes that Staff raised this point in an academic way but provided no quantitative analysis or even examples that supported this abstract concern.

Finally, the Commission concludes that IP's proposal is superior to IIEC's proposal that the SG customer and IP should be required to enter into a contract to specify the customer's SCR. IIEC's proposal would entail unnecessary administrative costs and burdens, whereas under IP's proposal the customer simply specifies its SCR; it is up to the customer to provide a reliable estimate, and no negotiation process is required. In addition, the Commission notes that, as pointed out by IP, IIEC's proposal leaves many important questions about its implementation unanswered. Accordingly, the Commission approves IP's SCR provisions for SG customers, as modified by IP during the course of this proceeding.

4. Lighting DST Rate Design

Under IP's proposed tariffs, rates for Outdoor Area Lighting have been separated into residential and non-residential, in light of the availability of delivery services to residential customers commencing May 1, 2002. For non-residential Outdoor Area Lighting service and Municipal Street Lighting service, the current charges for each type of bulb have been adjusted on a pro rata basis to arrive at the total non-residential Lighting revenue requirement. IP developed the proposed residential DST rates for Outdoor Area Lighting in the following manner: First, the current Outdoor Area Lighting bundled rates were adjusted for the 5% rate reduction scheduled for May 1, 2002. Second, the marginal cost of energy that was used to develop the prices for existing bundled Outdoor Area Lighting service was subtracted from the adjusted bundled price for each type of bulb. IP states that this step is consistent with the manner in which the non-residential Lighting DST rates were developed in the 1999 DST Case. Finally, the charges for each type of bulb were further adjusted pro rata to arrive at the total residential Lighting revenue requirement. (IP Ex. 6.10, p. 13) No other witness proposed any alternative rate design or prices to IP's proposal for the Lighting rates. (IP Init. Br., pp. 99-100)

The Commission concludes that IP's DST rate design for residential and non-residential lighting customers is reasonable and should be approved.

5. Metering Charges for DST Customers

a. IP's Position

IP determined the revenue requirement for meters subject to unbundling and presented an ECOSS for meters subject to unbundling to allocate the meter revenue requirement to the customer classes. IP states that the meter revenue requirement was calculated using the same criteria that were approved in the meter unbundling case, Docket 99-0013. Based on the results of these studies, IP has proposed non-residential meter charges (i.e., for small use general service and demand-metered general service DST customers) that recover the embedded cost of service. (IP Ex. 6.6, p. 11; IP Ex. 6.10, pp. 6-8) IP notes that Staff witness Lazare proposed essentially the same meter charges as did IP, with a one to two cents difference in the monthly metering charges to small use general service customers, apparently due to rounding in attempting to arrive at the total class revenue requirement. (Staff Ex. 22.0, Sched. 14.4 Rev. and 14.5 Rev.) IP notes that other party presented meter charges that differed from IP's proposed charges. (IP Init. Br., pp. 100-01)

b. IIEC's Position

IIEC supports an equal percentage increase in the facilities charges, metering charges and demand charges for the demand-metered class. IIEC states that IP's proposed metering charges represent an 1,100% increase for 138 kV transmission voltage customers. (See IIEC Init. Br., p. 19) IIEC notes its objection to the use of replacement meter costs to allocate the embedded cost of meters to the customer classes in the ECOSS, and its concern about the large amounts of G&I plant and A&G expense allocated to the metering function, as summarized earlier in this Order.

c. Commission's Analysis and Conclusion

The Commission concludes that the metering charges for small use general services and demand-metered residential DST customers, as proposed by IP and essentially concurred in by Staff, should be adopted. IP's metering charges were developed in accordance with the methodology approved in the meter unbundling case, Docket 99-0013. The Commission rejects IIEC's proposal for an equal percentage increase in the facilities charges, metering charges and demand charges for the demand-metered class, as not based on cost of service and, in the case of the metering charges, not based on the criteria approved in Docket 99-0013.

IV. DELIVERY SERVICES TARIFF TERMS AND CONDITIONS

A. Overview of IP's DST Simplification and Reorganization

As a part of its filing, IP chose to undertake a re-write of its DST and related tariffs. The parties to this proceeding were eventually in general agreement regarding the changes in the terms and conditions, except as noted in the following subsections of this Order. The changes to which there are no disputes are identified below.

B. Uncontested Issues

1. Off-Cycle Switching Fees

Off-cycle switching is a service that permits customers to begin taking delivery services on a date other than on the date that would be used in the normal course of business. Originally, IP required an enrollment process for off-cycle switching but has now proposed eliminating that process; under the revised process, the RES submitting the DASR will only need to check the appropriate field on the DASR to elect off-cycle switching. (See IP Ex. 7.1, p. 6) IP is also proposing to permit off-cycle switching via EDI as well. (Id.) In setting its fees for this service, IP determined that four categories should be used based on whether the off-cycle switching request was manual or EDI and whether the customer had an interval meter. (Id., p. 7) (IP Init. Br., pp. 102-03) IP has set an appropriate fee for each category. No party objected to IP's proposed charges nor did any party present any evidence for a different charge for these items. The Commission finds that the off-cycle switching options and the associated fees presented by IP are supported by the record and are hereby approved.

2. PPO Calculator Fees

IP currently offers the Power Purchase Option ("PPO") pursuant to § 16-110 of the PUA and its Rider PPO. IP has now developed a web-based PPO Calculator that permits RESs, customers and agents to perform the calculations on their own. (Id., pp. 8-9) IP proposes a fee of $4.50 per service classification calculation per account if the RES or customer uses the web-based calculator and $12.50 per service classification calculation per account if IP performs the calculation manually for the requestor. (Id.) (IP Init. Br., pp. 103-04) No party objected to IP's proposed charge nor did any party present any evidence for a different charge for this item. The Commission finds that the fees presented by IP for use of the web-based PPO Calculator are supported by the record and are hereby approved.

3. PPO Calculator/Customer Usage Data – Monthly Fees

Generally, customers and their authorized agents, as well as RESs, can obtain customer usage data from IP by requesting it and paying a fee for each such request. IP accepts EDI and manual requests and has developed a variety of web-based services. (See generally IP Ex. 7.1, p. 4) To provide RESs and agents with an alternative to paying a separate fee for each request for customer data, IP has proposed a monthly charge of $47.00 for any RES or agent that obtains customer data via IP's web-based applications (including its PPO calculator, described above). (IP Ex. 7.1, pp. 4-5) IP will require that those choosing this option enter into a contract for a 12-month period. (Id., p. 5) IP presented evidence of the cost-basis for its proposed fee. (See IP Ex. 8.1, p. 6; IP Ex. 8.4) RESs and agents do not need to pay the monthly fee. Instead, they can choose to continue paying the separate charge each time they request customer data. Furthermore, requests for interval metered data, manual requests and EDI requests will continue to be assessed a separate fee. (IP Ex. 7.1, p. 5) (IP Init. Br., p. 105) No party objected to IP's proposed charge nor did any party present any evidence for a different charge for this item. The Commission finds that the monthly fees presented by IP are supported by the record and are hereby approved.

4. Single Bill Option Credit

In IP's 1999 DST Case, the Commission developed a method to determine the credit a RES receives when it undertakes to bill the retail customer for both its own charges and IP's delivery services charges. (See 1999 DST Order, pp. 126-30) The adopted methodology used embedded costs to set the credit. (See id., pp. 129-30) IP updated this analysis for the current case using more recent data but employing the same methodology that was approved in the prior case. (IP Ex. 8.1, p. 7) (IP Init. Br., pp. 106)

Although the same cost categories apply to both residential and non-residential customers, IP developed separate fees for these two groups because of a difference in uncollectible expenses between the two groups. (Id.) Separate fees were also determined based on whether the RES assumes responsibility for payment and whether the customer is an electric-only customer or a combination gas and electric customer. (Id., p. 8) In the latter case, IP must continue to send a bill to the customer and, therefore, continues to incur the costs of preparing a bill. (Id.) Under these circumstances, the only time a credit is warranted is when the RES assumes responsibility for payment. The SBO credits, based on the evidence in this record, are as follows: (1) $0.439 and $1.133, for residential and non-residential electric-only customers, respectively, if the RES assumes responsibility for payment; (2) $0.213 for residential and non-residential electric-only customers if the RES does not assume responsibility for payment; and (3) $0.226 and $0.920, for residential and non-residential combination customers, respectively, applicable only if the RES assumes responsibility for payment. (See IP Ex. 8.1, p. 8; IP Ex. 8.7) No party objected to IP's proposed credits nor did any party present any evidence for a different credits for these items. (IP Init. Br., pp. 106-07) The Commission finds that the SBO credits presented by IP are supported by the record and are hereby approved.

5. Copy Fee

IP has proposed a standard copying fee of $0.25 per page for requests for copies other than customer usage and PPO calculator requests. (See IP Ex. 5.1, pp. 5-6; IP Ex. 5.3, p. 7) Because most items can be obtained electronically, the need for copying should now be minimized, and any associated costs should be imposed on those who insist on receiving paper copies of documents. (IP Init. Br., pp. 107) No party objected to IP's proposed charge nor did any party present any evidence for a different charge for this item. The Commission finds that the copying fee presented by IP is supported by the record and is hereby approved.

6. Transition Charges

Currently, IP has in place Rider TC to calculate a customer's TC either individually or on a class basis, along with a market value index ("MVI") tariff (Rider MVI) to set the market price of the power and energy used in calculating TCs. To accommodate residential customers who take delivery services, IP has updated Rider TC. (See generally IP Ex. 6.1, pp. 23-27 and IP Ex. 5.7) IP proposes to calculate only group TCs for residential customers. While the PUA requires individual TC calculations for customers with loads greater than 1,000 kW, IP voluntarily calculates individual TCs for customers over 100 kW. Nonetheless, even this lower limit remains substantially above the typical residential customer's demand of about 5 kW. (See IP Ex. 6.1, p. 23) (IP Init. Br., pp. 107-08)

To avoid disproportionate impacts that could be seen by individual residential customers if only a few TC groups were established for TC calculations, the Company has created multiple TC groups for each of its current residential service classifications (SC 2 and SC 3). (Id., p. 25) The groups are based not only on which service classification the customer is served, but also on such factors as usage, whether the customer is a space heat or non-space heat customer, and whether service is single phase or three phase. (Id., p. 24) This results in TC groups that have more homogeneity, and therefore, more equitably sets TCs for all parties. (Id., p. 25) The Company's rationale and approach is similar to the one it uses in determining non-residential TCs. Furthermore, IP made adjustments for the market values in marketing and uncollectible costs for calculating TCs. (See 1999 Order, p. 110) IP updated this adjustment based on test year costs and expenses as derived from FERC Form 1. (IP Ex. 8.1, p. 9) No party objected to IP's proposed changes nor did any party present any evidence for a different change for this item. (IP Init. Br., p. 108) The Commission finds that the IP's revisions to Rider TC are supported by the record and are hereby approved.

7. Rider PPO

a. Additional Charge to Recover Cost of Required Payments to State of Illinois Energy Efficiency Fund

Initially, IP included its *pro rata* share of the annual assessment under the Renewable Energy Efficiency and Coal Resources Development Law of 1997 in its distribution operating expenses as part of the distribution revenue requirement. After reviewing Staff's position on this expense, the IP agreed that this assessment (which is based on kWhs sold and not kWhs delivered) should not be recovered through its delivery services charges. (IP Ex. 5.11, pp. 1-2) Accordingly, IP excluded its assessment from its revenue requirement. (See Section II.C.2, above; IP Ex. 5.11, pp. 1-2; IP Ex. 1.34, p. 30; Rev. IP Ex. 3.24, p. 3, col. (33)) However, for consistency, IP proposed that those customers served under SC 110 who take energy supply from

IP (i.e., PPO customers and those on ISS) pay their ratable share of this expense. (IP Ex. 5.11, p. 2) Based on the total test year assessment divided by the total Company kWhs sold in the test year, the incremental charge is 0.0025¢/kWh. (Id.) No party objected to IP's proposed addition to the PPO or ISS charges nor did any party present any evidence for a different charge for this item. (IP Init. Br., p. 111) The Commission finds that the additional charge of 0.0025¢/kWh for energy sold under Riders PPO and ISS is supported by the record and are hereby approved.

b. Pricing Options for Non-Firm PPO Customer During Higher Energy Periods and Buy-Through Situations

IP has proposed to change Rider PPO to address a situation that can arise for those customers who take non-firm PPO service. Currently, under Section 8 of Rider PPO, if the Company invokes the higher energy or buy-through provisions of its interruptible rates, the charge to the customer is the price specified in the applicable interruptible service classification. Assuming the market value used in setting non-firm PPO prices is below the higher energy or buy-through energy price, this sends the proper signal for customers to either curtail their loads or pay the higher price. However, if the non-firm PPO market value is in fact above the applicable higher energy or buy-through rate, then the intent behind these rates (which is to serve as an alternative to curtailing load) is defeated. (See generally IP Ex. 5.1, p. 14) To alleviate this possibility, the Company proposed setting the non-firm PPO price at the higher of the non-firm MVI price or the otherwise applicable higher energy/buy-through price. (Id.) No party objected to IP's proposed changes nor did any party present any evidence for a different change for this item. (IP Init. Br., p. 112) The Commission finds IP's proposal to set non-firm PPO price at the higher of the non-firm MVI price or the otherwise applicable higher energy/buy-through price is supported by the record and are hereby approved.

c. Adjustment of Billing for Transmission Energy Loss Factor

IP has proposed that Rider PPO include additional language that clarifies an issue so that PPO customers realize that they are not paying for transmission losses twice. The issue arises because the market values set forth in Rider TC (which are also used to bill a customer energy under Rider PPO) have been adjusted for both transmission and distribution losses. However, the PPO customer already pays for transmission losses under Schedule 9 of the OATT. Therefore, IP proposes to include language in Rider PPO to clarify that a customer's billing for power and energy will be reduced by the transmission energy loss factor. (IP Ex. 5.1, p. 15) No party objected to IP's proposed changes nor did any party present any evidence for a different change for this item. (IP Init. Br., pp. 112-13) The Commission finds IP's proposal to clarify Rider PPO with respect to transmission losses is supported by the record and is hereby approved.

8. Use of Electronic Signatures for Customers – RES Letters of Agency

In this proceeding, Staff raised an issue regarding whether IP should permit electronic signatures (as compared to "wet" signatures) to be valid for customers "signing" an LOA. (Staff Ex. 7.0, pp. 6-10) Staff recognized that its proposal raised issues that might be better resolved in a workshop process and suggested that such a process be initiated for interested parties. (Id., p. 10; see also Tr. 561) (See Staff Init. Br., pp. 101-02) While IP has some concerns about the use of electronic signatures (including their legality given the current wording of various applicable statutes), it is not opposed to them in the abstract and is willing to work with Staff in workshops to resolve various issues surrounding their use. (IP Ex. 5.11, pp. 2-3) (IP Init. Br., pp. 131-32) In light of the consensus among those parties who provided testimony on this issue that this issue is better addressed in workshops, the Parties recommended that the Commission should not attempt to resolve this issue at this time but rather permit the parties a chance to resolve this matter informally. The Commission agrees with the position of the Parties and shall allow this issue to be resolved through the workshop process.

9. Agreement for "Billing Agents" Relating to Collection and Remittance of IFC Charges

At one point in this case, the Parties disagreed on the text of an agreement for "Billing Agents" relating to the collection and remittance of IFC charges; however, a resolution of this issue was ultimately presented by the parties during the proceedings. (See Tr. 621-22; MEC's Cross Ex. 1. *Cf*. Tr. 564) (See IP Init. Br., p. 131) Under the resolution, IP's proposed Section 6(u) of its Standard Terms & Conditions would be replaced with the following language:

> Any commercial entity receiving utility's electric charges to customer and assuming responsibility for remitting payment of utility's electric charges from or on behalf of customer, must sign an agreement provided by utility governing the remittance of IFC payments to utility.

The Parties also agreed that MidAmerican Cross Ex. 1 would be used as a generic agreement that fulfills IP's (and a third party collector's) obligations under that revised section. In light of the Parties' resolution of this issue and the support of the record, the Commission hereby approves the revised language to Section 6(u) of IP's Standard Terms & Conditions and the use of MidAmerican Cross Ex. 1 as a generic agreement that fulfills IP's (and a third party collector's) obligations under that revised section. (IP Init. Br., p. 131)

C. Contested Issues

1. Rider PPO – Addition of Factor A4c for Energy Imbalance Cost

Currently, IP's delivery service revenue used to calculate TCs includes a factor (known as Factor A4c) for energy imbalance revenues. (See IP Ex. 5.1, p. 13) At the time this factor was established, IP's Open Access Transmission Tariff ("OATT") permitted IP to retain energy imbalance revenues it received in excess of its costs. (Id.) Since that time, however, IP's OATT has changed such that IP must credit energy imbalance revenues in excess of its costs back to transmission customers. (Id.) Therefore, IP's net imbalance revenues (after the credit is included) will calculate to 0. (Id., pp. 13-14) Given this fact, IP has proposed setting Factor A4c at 0. (IP Init. Br., p. 109) No party has objected to IP's proposed value for Factor A4c, and the Commission finds that IP's proposed value is supported by the record and is hereby approved.

However, as explained above, Factor A4c adds to the delivery service revenue component of the TC calculation an amount to reflect IP's net revenues from energy imbalance service. Because of the equation used for calculating TCs, this addition lowers the TCs paid by a customer. PPO customers (who to be eligible must have a positive TC) are not charged for energy imbalances. (See IP Ex. 5.1, p. 15; 1999 DST Order, p. 118) To fix this problem, IP proposes adding Factor A4c to the price a PPO customer pays under Rider PPO. (Id.) (IP Init. Br., pp. 109-10) IIEC opposes changing Rider PPO in the manner described above.

a. IIEC's Position

The IIEC contends that there is too much uncertainty in the events that could cause Factor A4c to change in the future. (IIEC's Brief at 35). Specifically, the IIEC notes that IP will eventually be charging for transmission service under the Alliance RTO OATT, and that the manner in which the energy imbalance tariff will operate is simply unknown. (Id.) Accordingly, the IIEC believes that this perceived uncertainty requires the Commission to reject IP's proposed change to Rider PPO and further suggest that IP would be allowed to file for a change to Rider PPO to add Factor A4c in the event it becomes positive in the future. (IIEC Ex. 1, pp. 32-33, IIEC Ex. 4, p. 29) (IIEC Init. Br., pp. 34-35)

b. IP's Position

IP explains that regardless of the events that might transpire in the future to alter the value of Factor A4c, it is clear that if the Factor is omitted from Rider PPO, PPO customers will be receiving a credit in the calculation of their TCs for charges they do not pay because no imbalance charges are paid by PPO customers. Consequently, this asymmetry may effect a RES ability to compete for these customers because the total cost of service under PPO (an alternative supply option available to any non-residential customer with a positive TC) is reduce below what it would otherwise cost. Furthermore, IP notes if it is required to file for changes in the event Factor A4c becomes positive in the future, there may be time delays in implementation, which could cause unwarranted benefits to PPO customers and further disadvantage RES competing for that business. (IP's brief at 110-11) (IP Init. Br., pp. 110-11)

c. Commission's Analysis and Conclusion

The IIEC bases its position on unknown factors that may or may not ultimately have an impact on Factor A4c and IP's PPO service. However, the Commission finds that it is important for IP's PPO service to be priced to accurately reflects the known cost involved. Currently, IP's PPO customers are not charged for energy imbalances. Adding Factor A4c to the price a PPO customer pays under Rider PPO properly adjusts IP's Rider PPO for changes to reflect reality. Furthermore, since the FERC regulates the imbalance service, IP will not be able to unilaterally set the price for this service in the future. Accordingly, the Commission finds that IP's proposed change to Rider PPO to add Factor A4c to the price a PPO customer pays under Rider PPO is supported by the record and is hereby approved.

2. Rider ISS

a. General Overview

In IP's 1999 DST case, the Commission approved IP's ISS provisions for delivery services for non-residential delivery service customers. As a part of its tariff re-write process, IP proposes moving this service to a separate rider (Rider ISS) and adding certain language to accommodate residential delivery services customers. IP's Rider ISS is intended to provide energy to a customer who finds himself or herself temporarily without a supplier. In setting the

ISS price for residential customers, IP chose to use the same pricing mechanism that it uses for non-residential customers. (See IP Ex. 5.1, p. 16; IP Ex. 5.9) (IP Init. Br., pp. 113-14) The service is priced at IP's DA-RTP pricing, plus a 10 percent adder, and a 0.9-cent per kWh Recovery Factor.

IP also proposes to offer a service under which a residential customer whose ISS price was more than 120% of the customer's average bundled bill could choose to have the amount above 120% spread out over three months in those instances where the difference is more than $25. (IP Ex. 5.1, p. 17) The customer would pay interest on the portion that was being spread over the additional months, but would also see a somewhat levelized bill. (IP Init. Br., p. 114) IP's Rider ISS also provides that a customer who is served by a RES and then ends up on ISS cannot return to service from that particular RES for 12 months. (IP Init. Br., p. 120)

b. Pricing for Residential Customers

(1) Staff's Position

Staff did not object to IP's proposal to offer Interim Supply Service to residential DST customers. Staff did initially oppose the price structure for the interim service. As an alternative, Staff proposed to cap charges to residential customers at under Rider ISS at bundled rate plus a 10 percent adder. Staff contended that its proposed rate is intended to reduce the barrier presents to residential customers to participate in the competitive market. However, Staff has apparently abandoned its ISS pricing structure, as it made no mention of it in its initial brief.

(2) IP's Position

IP's explains that Staff has acknowledged that the IP could be faced with excess expenditures that far exceed the price the IP could charge. (See e.g., Tr. 535) And ultimately, any excess ISS costs incurred by IP may be socialized across all customers who take delivery services at some future time, rather than having those specific customers who cause the Company to incur these excess costs pay for those costs at the time they are incurred. (IP's Brief at 116)

Furthermore, as explained in its testimony and briefs, IP contends that both Staff's proposed pricing structure and the IIEC's proposals for Rider ISS would allow for gaming of the tariffs by customers and Retail Electric Suppliers. (IP Init. Br., p. 118, citing IP Ex. 11.1, p. 14) IP also believes that this potential for gaming could stifle the development of a competitive market in the territory. In support of its position, IP explains that if Rider ISS is priced below the price an alternative supplier could offer, this would allow RES the incentives to use ISS for their customers and not to develop competitive alternatives to ISS. (IP Init. Br., pp. 118-19) Accordingly, IP believes that Rider ISS should be above the market rate: that rate a customer is likely to see from a competitive market and their alternative supplier. (IP Init. Br., p. 115; Tr. 532-33)

(3) IIEC's Position

The IIEC has also taken the position that Staff's pricing structure for Rider ISS, bundled rate plus 10 percent adder, is patently discriminatory and cannot be justified. (IIEC Init. Br., p.

30) Specifically, the IIEC notes under Staff's pricing structure that residential and non-residential customers will be treated differently. (Id., pp. 30-31)

(4) Commission's Analysis and Conclusion

In IP's 1999 DST Case, the Commission approved IP's current pricing for ISS based on the Company's Real Time Pricing ("RTP") rate. (1999 DST Order, pp. 123-24) At that time, the Commission explained that the purpose behind this pricing mechanism is that "default service *should be temporary in nature and that it must not be a vehicle for rate arbitrage*. (Id., p. 124 (emphasis added)) More recently, the Commission has rejected ISS pricing that "would provide opportunities and incentives for RES's and residential customers to game the system. . ." (Docket 00-0802, Order, p. 50)

IP proposes pricing ISS at IP's DA-RTP pricing, plus a 10 percent adder, and a 0.9-cent per kWh Recovery Factor. The evidence in the case supports the Company's position that the proposed pricing structure reflects appropriate pricing for providing that service. The Commission finds that such pricing structure will assist in preventing "gaming" opportunities. Accordingly, the Commission hereby approves IP's proposed pricing structure.

c. IIEC Pricing Issues

(1) IIEC's Position

The IIEC does not disagree with IP's use of RTP pricing to set ISS energy Price. Rather, it is IIEC's position that IP should not be allowed to charge the current 10% adder on top of the energy prices under Rider ISS. IIEC acknowledges that IP should be entitled to recover real administrative costs involved in provided service under Rider ISS, but contends that IP has not demonstrated that it incurs actual administrative cost. (IIEC Brief at 26) Similarly, IIEC contends that IP should not be allowed to impose the fixed Recovery Factor of 0.9 cents per kWh. Finally, IIEC disagrees with IP's recovery of firm point-to-point-transmission service as a component charge of Rider ISS. (IIEC Init. Br., pp. 25-26)

(2) IP's Position

IP contends that the adders in its pricing structure are justified and supported by the record. IP explains that DA-RTP pricing is intended to recover the market energy price at the time the customer is taking Rider DA-RTP. Conversely, ISS is an unbundled service whereby the utility may be required to serve a customer's entire load on no notice for a very short period when energy prices may be extraordinarily high. (IP Init. Br., p. 118) Accordingly, a pricing structure with the inclusion of the adders better reflects the market price for providing the service.

Finally, it is IP's contention that the IIEC's position regarding the way transmission service is priced is not properly before the Commission for review at this time. The pricing methodology under Rider ISS was approved by the Commission in the 1999 DST case and is no different that such pricing under IP's current tariffs. In any event, IP also explains that point-to-point billing determinants are a better model for short-term uncertain service such as ISS (IP's Brief at 119) First, point-to-point service is available on a daily basis, whereas, network service is normally an annual service paid on a monthly basis. Second, under network service, billing determinants can lead to distortions in billing to otherwise identical customers; based solely on which days of which months the customers take ISS. Such distortions do not arise under point-to-point service. (Id.) (IP Init. Br., pp. 117, 119)

(3) Commission's Analysis and Conclusion

As described above, IP proposes pricing ISS at IP's DA-RTP pricing, plus a 10 percent adder, and a 0.9-cent per kWh Recovery Factor. The evidence presented by IP's supports its position that its pricing structure represents the market rate of ISS service. Furthermore, the Commission finds that such pricing structure will assist preventing "gaming" opportunities. The Commission also finds that IP's use of point-to-point service more accurately represents the rate involved in providing the service. Accordingly, the Commission hereby approves IP's ISS pricing structure that includes a 10 percent adder, and a 0.9-cent per kWh Recovery Factor and further approves the usage of the point-to-point billing determinants.

d. Customer Moving from a RES to ISS Cannot Return to that RES for 12 Months

(1) Staff's Position

Staff opposes IP's proposal to limit customers from returning to their former supplier because it might leave a customer dependent on IP for electric service in the event there are no other suppliers. (Staff Init. Br., p. 91, citing Staff Ex. 7.0 p. 13) Staff also contends that such limitation would put the Commission in the position of forbidding a customer from taking service from a legally authorized supplier. (Staff Init. Br., p. 91) Staff proposes removing such limitation from IP's Rider ISS and adding the language in the tariff that states that ISS should not be used a supply source. (Staff Ex. 7.0, p. 14)

(2) MEC's Position

MEC does not oppose IP's price structure for Rider ISS. However, MEC objects to the limitation that prevents a customer from returning to their previous RES in the event that the customer is placed on ISS. MEC contends that such prohibition will constrict the available supplier market at a time when residential choice is in its infancy. Furthermore, MEC contends that IP already has a solution to the "gaming" threat by offering ISS service at a price level as high or higher than competitive offerings. (MEC Init. Br., p. 3)

(3) IP's Position

IP contends that the 12-month limitation on returning to a former RES (in the event that a customer is placed on ISS) prevents a given RES from using ISS as a supply option for certain periods. Specifically, this limitation would prevent a RES from dumping customers onto Rider ISS when market prices are high. (IP Init. Br., p. 120) IP contends that Staff's proposed hortatory language does not adequately address this potential scenario because it merely suggests that Rider ISS should not be used as a gaming tool. Furthermore, the IP notes that in no event does the limitation prevent a customer from choosing a different RES. And the current market conditions in IP's service territory indicate that there will be a number of market participants to dispel any concern that there would not be ample RES for the residential customer to choose as their supplier.

(4) Commission's Analysis and Conclusion

The Commission finds that IP's 12-month limitation on returning to a former RES would reasonably prevent RES and residential customers from "gaming" the system by relying on Rider ISS for energy supply when the market rate is high. As noted above, one of the fundamental points recognized by this Commission is that RESs should not be allowed to use ISS as a gaming opportunity. This provision directly prevents RESs from using ISS as a gaming opportunity. Specifically, a customer who is served by a RES and then ends up on ISS cannot return to service from that RES for 12 months. The Commission further concludes that Staff's proposed language would not adequately prevent RES from "gaming" the system because it merely suggests that Rider ISS should not be used as a "gaming" tool. Accordingly, the Commission hereby approves IP's 12-month limitation on returning to a former RES after being placed on ISS.

3. Ability of Customer to Rescind Notice of Return to Bundled Service Within 30-day Notice Period

Under IP's proposed tariffs, once a customer gives IP notice that it desires to return to bundled service, that customer may not rescind that notice during the 30-day period preceding the switch. (IP Ex. 5.1, p. 8) A customer remains free to rescind its notice prior to the final 30-day period, but once it reaches that period, rescission is not permitted. (IP Init. Br., p. 123)

Staff was the only party to disagree with IP's proposal. However, at the hearings, Staff agreed that (1) IP should be entitled to recover its legitimate costs associated with a right of rescission, and (2) resolution of this issue would be better handled in a workshop process. (Tr. 563) IP agreed with Staff's recommendation to handle this issue in a workshop. However, in the interim, IP contends that the proposed language should be adopted, since no mechanism currently exists for IP to recover its legitimate costs if different language were used. (IP Init. Br., p. 123) The Commission finds that IP's proposal is reasonable under the circumstances and hereby approves the IP's 30-day rescission provision.

4. Residential and Small Commercial Customers to Remain on Bundled Service for 24 Months After Returning from Delivery Service

Currently, IP requires that any small commercial customer (as defined in PUA §16-102) who returns to bundled service after having been on delivery service must remain on bundled service for 24 months before returning to delivery services. This provision is in accord with §16-103(d). For residential customers, IP also proposes making the return to bundled rates be 24 months as permitted by §16-103(d). (IP Ex. 5.1, p. 7) (IP Init. Br., pp. 123-24)

a. Staff's Position

In Staff's opinion, an electric utility imposing a 24-month requirement would be imposing a harsh penalty on customers. Moreover, Staff contends that the 24-month requirement would be especially punitive towards those customers who might wish to return to delivery services. (Staff Ex. 7.0, p. 11). Staff recommends that IP only require smaller-use customers returning to bundled service from delivery services to stay on the IP's bundled services for 12 months, rather than 24, as the IP proposes. (Staff Init. Br., p. 104)

b. IP's Position

IP notes that the General Assembly expressly authorized electric utilities to include a 24-month return requirement for these customers; thus, contends that Staff's pejorative reference to a "harsh penalty" is out of place and misdirected. In any event, IP contends that the 24-month requirement was part of a broader *quid pro quo* that included obligations on the part of the utility, such as the obligation to continue offering bundled services and the obligation to allow customers to return from delivery services to bundled services on little or no notice. (IP Ex. 5.11, p. 3) (IP Init. Br., p. 124)

c. Commission's Analysis and Conclusion

Under IP's proposed tariff, residential delivery service customers that return to bundled service are subject to such service for a minimum of 24 months. Under the Act, IP is authorized to impose this requirement. Accordingly, the Commission finds that IP's proposal to require residential delivery service customers that return to bundled service to be subject to such service for a minimum of 24 months is supported by the record and hereby approved.

5. IIEC Issues Related to Departure from and Return to Bundled Service

Under IP's bundled SC 24, a customer who wishes to terminate service under that tariff must provide 12-month notice to do so (assuming it has already fulfilled its primary term obligation under SC 24). IP also adopted a policy that permitted a customer to rescind this notice (and thereby remain on SC 24 for another 12-month period) up to 60 days before the termination date. (IP Ex. 5.11, p. 15) (IP Init. Br., p. 125) Furthermore, a customer that returns to SC 24 after taking delivery services must satisfy the primary term obligation before it may terminate service. IP also has a policy that forbids a customer who left closed interruptible tariffs (i.e., SC 30 and Rider S) prior to the Customer Choice Law becoming law, from returning to those rates.

The IIEC has raised three issues relating to the operation of IP's bundled tariffs. Specifically, the IIEC seeks to change the notice requirement to terminate service under SC 24, eliminate the primary term obligation for customers returning to SC 24 after taking delivery service, and allow customers who have chosen delivery service to return to bundled tariffs that are closed. (See IIEC Init. Br., pp. 35-36)

a. Notice Required to Terminate SC 24 Contract

(1) IIEC's Position

IIEC recommends that a SC 24 customer that has satisfied the primary term obligation be permitted to give IP 30 days notice of its intent to take delivery service. IIEC believes that this can be accomplished by inserting an appropriate provision within SC 110. (IIEC Init. Br., 35-36)

(2) IP's Position

First, as a general objection to all of IIEC's issues related to SC 24, IP explains that it has not sought to modify any single bundled tariff that the IIEC attempts to change. Thus, IP contends that the IIEC seeks to expand the scope of this case beyond what it rightfully should be: a delivery services tariff case. Furthermore, IP explains that the issues IIEC raises are not new; they have been raised by IIEC before and have been rejected by the Commission. (IP Ex. 5.11, p. 14) Accordingly, IP requests that the Commission reject the IIEC's proposed changes. (See IP Init. Br., pp. 124-25)

Moreover, IP provided extensive information regarding the interrelationship of SC 24 with other IP service classifications. (See IP Init. Br., pp. 125-27) IP notes that ultimately it is the customer's choice under which rate it takes service; and when it makes that choice, there are certain obligations and conditions that come with each rate. (IP Init. Br., p. 126) IP contends that the IIEC is merely attempting to retain the advantages of certain terms of SC 24 and attempting to eliminate other obligations.

Specifically, IP explains that SC 21 and SC 24 are two current bundled tariffs that are designed for customers with loads over 1 MW. These tariffs were in place long before the Customer Choice Law was enacted, with their basic frameworks in place prior to then as well (as even IIEC admits (Tr. 681-82)). SC 21 is the default tariff (i.e., the tariff on which a customer over 1 MW is served assuming it does not choose another available option). Generally, the choice between SC 21 and SC 24 involves a risk/return tradeoff that is embedded in the terms of which the IIEC now complains. (IP Ex. 5.12, p. 12) For example, in exchange for lower power and energy prices, the SC 24 customer commits to a longer primary term (5 years), longer notice to terminate service outside the primary term (12 months) and a guaranteed energy commitment than would occur for an SC 21 customer. Thus, it is the customer's choice under which rate it would like to be served, but, when it makes that choice, it knows (after weighing carefully) the obligations (and opportunities) that come with each rate. (See generally IP Ex. 5.12, p. 12) (IP Init. Br., pp. 125-26)

Finally, IP also notes that IIEC is concerned that 60 days is not enough time for customers to act because of all the steps they "must" take when deciding on supply alternatives to ISS (IIEC Init. Br., p. 27), yet these same customers now need only 30 days when they want to leave bundled service.

Accordingly, IP concludes that such proposals to eliminate the notice required to terminate a SC 24 contract is not only outside the context of this delivery service case; but would also cause certain inequitable differences between SC 24 and SC 21. (IP Init. Br., p. 126)

(3) Commission's Analysis and Conclusion

The Commission must reject the IIEC's proposals to eliminate the notice required to take delivery service and IIEC's recommendation that SC 24 customers returning to bundled service not be subject to a new five year primary term, as the IIEC has improperly sought to expand the scope of this proceeding. IP has not sought to modify any of its bundled tariffs as part of this proceeding; however, the IIEC has unilaterally sought to modify certain provisions of IP's bundled tariffs. Specifically, the IIEC attempts to eliminate certain provisions in SC 24, which ultimately would have the effect of making service under such bundled rate more attractive to large energy customers, which could ultimately have the effect of deterring competition in IP's territory. The Commission finds that such action cannot be allowed in the context of this delivery service case. Moreover, the IIEC's proposed changes merely attempts to re-address issues that have previously been rejected by the Commission. Accordingly, the Commission rejects the IIEC's proposed to IP's notice requirement

b. Ability to Return to SC 24 without Complying with the Primary Term Requirement of the Filed Tariff

(1) IIEC's Position

IIEC further recommends that SC 24 customers returning to bundled service not be subject to a new five year primary term. IIEC contends that these changes will reduce the barriers to competition in the IP service territory. (IIEC Init. Br., p. 36)

(2) IP's Position

IP notes that along the same lines as its attempt to permit SC 24 customers who have satisfied their primary term obligations to leave this bundled tariff more quickly than its terms allow, IIEC also wants these customers exempted from the primary term requirement of SC 24 if they *return* to SC 24 from delivery services. (IIEC Init. Br., p. 37) IP again notes the IIEC has refuses to focus on the interplay between SC 24 and other service classifications, specifically SC 21, even though it admitted that certain rates must be looked at in conjunction and not in isolation. (Tr. 683) (IP Init. Br., p. 127) Accordingly, IP contends that the IIEC is merely attempting to retain the advantages of certain terms of SC 24 and attempting to eliminate other obligations.

(3) Commissions Analysis and Conclusion

The Commission also reject IIEC's recommendation that SC 24 customers returning to bundled service not be subject to a new five year primary term, as the IIEC has improperly sought to expand the scope of this proceeding. IIEC attempts to eliminate certain provisions in SC 24, which ultimately would have the effect of making service under such bundled rate more attractive to large energy customers, which could ultimately have the effect of deterring competition in IP's territory. The Commission finds that such action cannot be allowed in the context of this delivery service case. Moreover, IIEC is merely attempting to IIEC is retain the advantages of certain terms of SC 24 and attempting to eliminate other obligations. Accordingly, the Commission rejects IIEC's recommendation that SC 24 customers returning to bundled service not be subject to a new five year primary term.

c. Ability to Return from Delivery Service to Closed Bundled Tariffs

(1) IIEC's Position

IIEC recommends that current Rider S and Rate SC 30 customers electing delivery service also be permitted to return to Rider S and SC 30. It is the IIEC's position that customers are likely to be discouraged from utilizing competitive supply if they cannot return to these rates. (IIEC Init. Br., p. 36)

(2) IP's Position

Along with IP's general objection to IIEC's proposed changes to SC 24 noted above, IP also explains that it has consistently administered its policy that its closed interruptible tariffs (i.e., SC 30 and Rider S) are closed and will not be "re-opened" to customers who choose to leave those tariffs (for whatever reason). (IP Ex. 5.12, p. 13) Thus, customers who left these rates (in order to firm up their service) prior to the Customer Choice Law becoming law, cannot return to these rates. (IP Ex. 5.11, p. 17) Similarly, those customers who made the same decision after the law was passed are also ineligible to return to them. (Id.) And, those that have already taken delivery services are ineligible to take service on the closed interruptible rates. (Id.) Thus, IP contends that the IIEC seeks is a discriminatory waiver to IP's longstanding, consistent practice to benefit those few customers who remain on these closed rates and have not yet taken delivery service. IP asserts that this is not fair to those customers who made choices based on a certain set of rules that IIEC now does not wish to follow. Furthermore, IP contends that it is unfair to require IP to provide a safety net of interruptible service on rates that have been closed for a decade. (IP Ex. 5.11, p. 17) This is particularly true since these rates are frozen until 2005 under PUA §16-111(a) -- IP cannot raise them to reflect the current cost of service. (IP Init. Br., pp. 127-28)

(3) Commission's Analysis and Conclusion

The Commission must again reject the IIEC's proposals to allow that current Rider S and Rate SC 30 customers electing delivery service to be permitted to return to Rider S and SC 30. As previously noted, IP has not sought to modify any of its bundled tariffs as part of this proceeding. Furthermore, IIEC seeks is a discriminatory waiver to IP's longstanding, consistent practice of preventing customers from returning to closed tariffs to benefit those few customers who remain on these closed rates and have not yet taken delivery service. The Commission finds that such action cannot be allowed in the context of this delivery service case. Accordingly, the Commission finds that IP's bundled tariffs shall continue as previously approved.

6. Responsibility of Retail Delivery Service Customer for OATT Charges not paid by the Customer's TSA or RES

IP's proposed DSTs include language that makes it clear that a retail customer remains ultimately liable for transmission charges if its RES or Transmission Service Agent ("TSA") fails to pay those charges. (See IP Ex. 5.5, p. 29) However, IP's tariff language also makes it clear that "[b]efore billing the charges to Customer, Utility shall first pursue all reasonable collection actions against Customer's RES . . . or TSA, including initiating a claim against any bond or other security the RES . . . or TSA has posted." (Id.) (IP Init. Br., p. 128)

a. IP's Position

It is IP's position that under its OATT, the retail delivery services customer is the transmission customer; the TSA or RES is acting as the retail customer's agent (assuming the retail customer does not take service directly under the OATT). (IP Ex. 5.11, p. 5) (IP Init. Br., p. 129) IP explains that there is no disagreement among the Parties that the "eligible customer" for transmission service under the OATT is the retail customer. (See, e.g., Tr. 473-74) Furthermore, even as Staff notes, the Transmission Customer is "[a]ny Eligible Customer (or its Designated Agent)." (Staff Init. Br., p. 94, n. 14). IP concludes that when a RES (which, by definition, is not the retail customer under the PUA) obtains transmission service for the retail customer it is doing so as the retail/eligible customer's designated agent. Thus, IP contends that its proposed language merely puts the retail customer on notice of an indisputable foundation of agency law; that is, the principal remains liable for debts incurred by its agent on its behalf. (See IP Init. Br., p. 129)

b. Staff's Position

Staff disputes whether in fact the OATT establishes the retail customer as the transmission customer and creates an agency relationship when a different party actually works on behalf of that customer. (Staff Ex. 8.0, p. 4; Staff Ex. 17.0, p. 3) (Staff Init. Br., p. 95) However, Staff acknowledges that if an agency relationship is created by the OATT, that relationship remains in place regardless of whether IP's SC 110 notifies the retail customer of this fact. (Staff Ex. 17.0, p. 3; Tr. 475-76)

c. IIEC's Position

IIEC also objects to IP's proposed language, asserting that a RES can take transmission service on its own behalf and ultimately be responsible for transmission arrangements and transmission charges. The IIEC contends that IP has "unfairly interpreted" its OATT to limit the parties that may be responsible for transmission service charges. Accordingly, the IIEC contends that IP's proposed language effectively alters certain provisions in its OATT. (IIEC Init. Br., p. 32)

d. Commission's Analysis and Conclusion

Under IP's OATT, a Service Agreement is entered into between a Transmission Customer and the Transmission Provider for transmission services. A Transmission Customer is defined as "[a]ny Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) request in writing that the Transmission Provider file with the Commission, a proposed unexecuted Service Agreement to receive transmission service under Part II of the Tariff. . . (IP OATT § 1.45) The "eligible customer" for transmission service under the OATT is the retail customer. Accordingly, the Commission finds that when a RES (which, by definition, is not the retail customer under the PUA) obtains transmission service for the retail customer, it is doing so as the retail/eligible customer's designated agent. IP's proposed language that makes it clear that a retail customer remains ultimately liable for transmission charges if the RES or TSA fails to pay for those charges. IP's also intends to include a provision that makes its clear that it shall first pursue all reasonable collection actions against Customer's RES. The Commission finds that such language is appropriate and hereby approved.

7. Splitting Electric and Gas Bills and Accounts

MEC has proposed that IP split the bills and accounts of combination gas and electric customers. (See MEC Ex. 1, p. 3; MEC Ex. 2, pp. 5-6) MEC clarifies its position by explaining that it is not advocating that IP be ordered to offer a split bill to all of its customers at this time, rather, it requests that IP find a way to handle to occasional customer that request this service. (MEC Init. Br., p 4) Staff (though generally in favor of splitting accounts) recognizes that doing this may impose both administrative burdens and added cost on IP. Thus, Staff proposes its monitoring the situation because of the financial and administrative costs associated with splitting bills. IP recommended that the Commission allow for all parties effected to addressed the issue of splitting bills in a workshop process or a generic docket in which all parties (including other combination utilities) could voice their concerns and time would permit the parties to better analyze the issues. (IP Ex. 5.12, pp. 15-16) (See IP Init. Br., pp. 132-33)

In light of the Parties' positions on this matter, the Commission concludes that the issues of splitting bills for combination customers would be more appropriately addressed in a different forum. An alternate forum will strike a proper balance and will lead to a more informed decision on this issue than can be arrived at based on the record in this proceeding.

8. Rider PRS

a. IIEC's Position

Originally, IP proposed substantive changes to its PRS service (in addition to moving it to a Rider, Rider PRS). However, in light of the problems raised by IIEC and the gaming opportunities raised by IIEC's alternative proposals, IP withdrew its proposed changes. (IP Ex. 6.6, p. 27; IP Ex. 6.14, p. 26) In its initial brief, IIEC attempts to resurrect its alternative; stating that under IP's current proposal, delivery service customers taking partial requirements from IP are treated in a discriminatory manner as compared to fully bundled customers.

b. IP's Position

IP first notes the its only proposal is to continue with the service that was approved by this Commission in its last DST case. Furthermore, IP explains that IIEC has neglected to point out that full-requirements bundled customers can only take DA-RTP for incremental load above their baseline usage. Moreover, there is no reason that alternative suppliers cannot (and indeed no evidence that they do not already) offer RTP pricing for delivery services customers such as those represented by the IIEC. There is thus nothing discriminatory in treating differently-situated customers differently.

c. Commission's Analysis and Conclusion

IP's current (and only) proposal is to continue with the service that was approved by this Commission in IP's last DST case. The Commission has previously found IP's PRS meets the requirements of the Act. (1999 DST Order, p. 125) Based on the evidence on this matter, the Commission finds that there is no reason IP's PRS should not continued on the same terms as currently provided.

V. FINDINGS AND ORDERING PARAGRAPHS

The Commission, having considered the entire record and being fully advised in the premises, is of the opinion and finds that:

(1) Illinois Power Company is an Illinois corporation engaged in the distribution and sale of electricity to customers at retail in this State, and as such is a public utility as defined in the Public Utilities Act;

(2) the Commission has jurisdiction over Illinois Power and the subject matter herein;

(3) the recitals of fact and conclusions reached in the prefatory portion of this Order are supported by the evidence of record and are hereby adopted as findings of fact; the attached Appendix A provides supporting calculations for various portions of this Order;

(4) the test year for the determination of the delivery services rates approved herein is the historic test year ended December 31, 2000; such test year is appropriate for purposes of this proceeding;

(5) for purposes of this proceeding, Illinois Power's delivery services rate base is $909,163,000;

(6) for purposes of this proceeding, Illinois Power's delivery services revenue requirement is $295,950,000;

(7) a just and reasonable rate of return which Illinois Power should be allowed to earn on its rate base is 8.69%; this rate of return incorporates a rate of return on common equity of 11.89%;

(8) Illinois Power's Service Classifications 110 and 150, and its Riders PPO, TC and ISS, and the proposed revisions to its Electric Standard Terms and Conditions and to its Rules, Regulations and Conditions Applying to Electric Service, as modified during the course of this proceeding or as further directed in the prefatory portion of this Order, are hereby deemed to be just and reasonable; Illinois Power is authorized to place these tariff sheets into effect and the tariff sheets shall be applicable to service furnished on and after their effective date of May 1, 2002;

(9) the interclass revenue allocation and rate design discussed and accepted in the prefatory portion of this Order are just and reasonable for purposes of this proceeding and should be adopted;

(10) Illinois Power shall file the new tariff sheets authorized to be filed by this Order within 10 days of the date of this Order in order to allow time for Staff review and for submission of corrected pages, if necessary, before the effective date of May 1, 2002 for those tariff sheets; and

(11) all objections, petitions or motions in this proceeding which remain undisposed of should be disposed of in a manner consistent with the ultimate conclusions contained in this Order.

IT IS THEREFORE ORDERED that Illinois Power Company is hereby authorized and directed to file new tariff sheets reflecting Service Classifications 110 and 150, and its Riders

PPO, TC and ISS, and its Electric Standard Terms and Conditions and its Rules, Regulations and Conditions Applying to Electric Service described herein, in accordance with the Commission's findings and conclusions herein.

IT IS FURTHER ORDERED that Illinois Power shall comply with Finding (10) of this Order.

IT IS FURTHER ORDERED that all objections, petitions or motions in this proceeding which remain undisposed of should be disposed of in a manner consistent with the ultimate conclusions contained in this Order.

IT IS FURTHER ORDERED that subject to the provisions of Section 10-113 of the Public Utilities Act and 83 Ill. Adm. Code Section 200.800, this Order is final; it is not subject to the Administrative Review Law.

By order of the Commission this __ day of _____, 2002.