STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

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

ILLINOIS POWER COMPANY'S BRIEF IN REPLY TO EXCEPTIONS TO THE ADMINISTRATIVE LAW JUDGE'S PROPOSED ORDER

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Illinois Power Company ("Illinois Power," "Company" or "IP") submits this Brief in Reply to Exceptions to the briefs on exceptions ("BOE") filed by the Commission Staff, the Illinois Industrial Energy Consumers ("IIEC"), the Citizens Utility Board and the Attorney General ("GCI") and Midwest Energy Alliance, L.L.C. ("MEA"). Except as noted below, these parties' exceptions to the Administrative Law Judge's Proposed Order ("PO") are unfounded and should be rejected.

IV. REVENUE REQUIREMENTS

B. Rate Base

2. Contested Adjustments

b. Post Test-Year Plant Additions – GCI's Arbitrary Limitation on Capital Additions Was Properly Rejected in the Proposed Order

The PO concludes that rate base should include post-December 31, 2000 capital additions that were completed, or had received funding approval from IP management, as of September 30, 2001. These were the capital additions that Staff found, after an extensive review, to satisfy the "known and measurable" test. Application of the "funding approval" criterion resulted in disallowance of a portion of the capital additions originally proposed by IP for inclusion in rate base; however, the Company accepted this criterion, as proposed by Staff, as the basis for determining the capital additions that should be included in rate base. (PO, pp. 18-19; see IP Init. Br., pp. 6-10; Staff Ex. 2.0, Sched. 2.1) As the Commission will recall, the issue of how to determine what post test-year plant additions and expenses were "known and measurable" was extremely controversial in the initial (1999) round of delivery services tariff ("DST") cases, including IP's 1999 DST Case (Dockets 99-0120 & 99-0134 (Cons.)), and resulted, among other things, in an appeal of Commonwealth Edison's 1999 DST order (Docket 99-0117), and reversal by the Appellate Court, on this issue. It is therefore significant that in this case, IP and Staff agreed on the criteria for determining which capital additions are "known and measurable" and on the application of the criteria to the capital additions that IP proposed to include in rate base.

GCI, however, argue that the capital additions in rate base should be limited to those placed in service as of June 30, 2001. (GCI BOE, p. 7 and App. C) GCI do not appear to really take issue with the "funding approval" test used by Staff, or with Staff's determination that the capital additions the PO includes in rate base are "known and measurable" additions to plant in service. In fact, GCI presented no analysis in their evidence in this case as to whether the specific capital additions that IP proposed for inclusion in rate base were known and measurable. GCI's witness apparently would prefer to include no capital additions, but he acknowledged that this would be inconsistent with this Commission's practices. (GCI Ex.2.0, p. 21) As presented by GCI's witness, the June 30, 2001 date had no specific basis, but rather was simply an arbitrary cut-off date.

The reasons given by GCI, in their BOE, for limiting capital additions to June 30, 2001, are that (1) IP has not extended the billing determinants used to set rates beyond the end of the test year, and (2) while the inclusion in rate base of capital additions that were completed or had received funding approval as of September 30, 2001, results in some projects being included in rate base that will not be completed until after that date, IP has only extended the accumulated reserve for depreciation and the accumulated reserve for deferred income taxes ("ADIT") on plant in service at December 31, 2000, through September 30, 2001. (GCI BOE, pp. 2-7) As shown below, these contentions do not warrant limiting capital additions to those in service as of June 30, 2001. Indeed, even if these contentions were correct, the "remedy" would be to revise the billing determinants used to set rates and to increase the depreciation reserve and ADIT components of rate base, <u>not</u> to cut back the capital additions from those found to be known and measurable by Staff and the PO to those in service as of June 30, 2001. GCI have provided no basis for limiting capital additions to those in service as of June 30, 2001, or for otherwise changing the PO's conclusion on the amount of capital additions to be included in rate base.

GCI's arguments as to billing determinants are misplaced in several respects. First, in its rebuttal testimony in this case, *IP accepted the adjustment to test year billing determinants that GCI's witness had proposed* in his direct testimony. In fact, IP implemented a <u>more significant</u> adjustment than GCI's witness had proposed. GCI's witness proposed only an adjustment to increase the number of residential customers in the billing determinants. IP increased the number of customers of all classes (non-residential as well as residential) in the billing determinants. (A corresponding adjustment was also made to increase kWh sales from all of the classes, consistent with the increased numbers of customers.) (See IP Ex. 6.6, pp. 3-4; Tr. 404) GCI's witness did not take issue, in his rebuttal testimony, with IP's adjustment to billing determinants, nor did he propose any further or different adjustment to billing determinants. In fact, he specifically testified that IP had adopted his proposed adjustment, acknowledged that IP had in fact gone beyond his adjustment by extending it to non-residential as well as residential customers, and testified that there was no remaining issue between IP and GCI as to billing determinants. (Tr. 403-04) For GCI now to suggest that the billing determinants IP used should be further adjusted is inconsistent with its own witness' testimony, disingenuous and untimely.

The adjustment to test year billing determinants that GCI witness Effron proposed and IP accepted was to use an average of actual 2000 customers and forecasted 2001 customers (with a corresponding increase to kWh sales). In criticizing the sufficiency of this adjustment in its BOE, GCI fail to mention that <u>the number of customers at year-end 2000 was lower than the average number of customers for the year</u>. (GCI Ex. 2.0, p. 31; IP Ex.6.6, p. 4) If IP had used an average of the actual year-end 2000 number of customers and the forecasted year-end 2001 number of customers (as GCI now appear to be suggesting), the increase in the billing determinants (numbers of customers and corresponding kWh sales) likely would have been smaller than the adjustment actually implemented by IP and accepted by GCI witness Effron.

In any event, GCI place undue weight on the importance of increasing billing determinants in lockstep with the amount of capital additions. Of the total distribution plant capital additions accepted by Staff as known and measurable, $92,738,667 (prior to adjustment for retirement of plant replaced by additions), only $34,525,922, or about 37%, is for projects to serve "new business", i.e., customers requesting service. (IP Ex. 2.18; see IP Ex. 2.1, p. 8) The remainder of the additions represent projects to rebuild facilities due to condition ($21.8 million); projects to rebuild facilities due to voltage criteria being exceeded or other overload conditions ($11.8 million); replacement of substation equipment ($18.3 million); and relocation of facilities, such as due to requests from governmental entities ($6.4 million). (IP Ex. 2.18; see IP Ex. 2.1, p. 8) Further, of the $34.5 million of distribution plant capital additions due to "new business", $27.3, or 79%, were actual expenditures as of September 30, 2001.[1] (See IP Ex. 2.18, p. 1)

Illinois Power adjusted the actual 2000 numbers of customers and kWh sales by increasing them to reflect the average of actual 2000 customers and forecasted 2001 customers. Based on Staff's application of the "known and measurable" criterion, IP proposed, and Staff and

[1] Given the long-lived nature of distribution equipment, new equipment installed today to replace facilities that must be retired or replaced due to condition, capacity, voltage requirements and similar reasons will have a higher installed dollar cost than the facilities being replaced. Thus, a distribution company would be expected to have growth in the aggregate dollar amount of its plant in service over time even if it had no growth in number of customers served. Further, increased attention to reliability issues by utilities, regulators and customers (as manifested in §16-125 of the Public Utilities Act ("PUA"), enacted in 1997, and 83 Ill. Adm. Code 411, promulgated as a result of §16-125) can be expected to result in an increasing proportion of capital additions being for rebuilds due to condition and capacity, as opposed to due to growth in numbers of customers.

the PO accepted, the inclusion in rate base of actual expenditures for capital additions, and remaining expenditures on projects that had received funding approval from management, as of September 30, 2001. Of the aggregate amount of capital additions for energy delivery-related projects (distribution plant, general plant and intangible plant) that were allowed, 83.6% were actual expenditures as of September 30, 2001. (See IP Init. Br., pp. 11-12) As noted above, only a portion of the capital additions amount represents additions to provide new service ordered by customers. The adjustment to increase billing determinants beyond the test year level, by averaging actual 2000 customers with projected 2001 customers and increasing kWh correspondingly, is a fair and appropriate adjustment to reflect growth in numbers of customers and kWh sales beyond the test year, consistent with the capital additions adjustment allowed by the PO. GCI have made no case for changing the capital additions amount approved by the PO; at most, GCI have made a case for a larger adjustment to billing determinants. However, the adjustment IP used was the adjustment GCI's witness proposed, and GCI have presented no alternative adjustment. Therefore, GCI's argument relating to billing determinants must be rejected.

GCI's other argument, relating to the degree to which IP has extended the accumulated reserve for depreciation and the reserve for ADIT beyond December 31, 2000, also does not justify any change in the amount of capital additions approved by the PO for inclusion in rate base. The most this argument could do would be to lead to an increase in the adjustments to the accumulated depreciation reserve and the reserve for ADIT that IP proposed and the PO accepted. However, as shown in the next section of this brief, no further changes to the adjustments to the depreciation reserve or to the ADIT reserve that the PO approved are warranted.

The capital additions amount approved by the PO for inclusion in rate base is based on an objective, verifiable criterion for identifying which projects are "known and measurable" that was developed and applied by Staff in a thorough review of the underlying documentation. (See IP Init. Br., pp. 6-10) GCI's proposal to instead arbitrarily limit the capital additions to projects placed in service by June 30, 2001, is unjustified and should be rejected by the Commission.

a. Accumulated Depreciation on Plant in Service at December 31, 2001

Response to Staff

IP agrees with the correction to the "Commission's Conclusion" on this adjustment proposed by Staff at page 2 of its BOE.

Response to GCI – The PO Appropriately Adjusts Rate Base for Additional Accumulated Depreciation and Deferred Taxes after December 31, 2000

In connection with the approved adjustment for capital additions, which consisted of actual expenditures, and remaining expenditures on projects that had received funding approval from management, as of September 30, 2001, IP also (i) increased the accumulated reserve for depreciation on plant in service at December 31, 2000, for additional depreciation through September 30, 2001; and (ii) increased the ADIT reserve relating to plant in service as of December 31, 2000, for activity through September 30, 2001. The adjustment for additional accumulated depreciation on plant in service at December 31, 2000 decreased rate base by $31,899,000 (see IP Ex. 3.24 Rev., p. 2, col. (24), line (7)); and the adjustment to the ADIT reserve for plant in service at December 31, 2000 decreased rate base by $3,448,000 (see IP Ex. 3.24 Rev., p. 3, col. (25), line (12)).[2] GCI complain that extending the reserves for accumulated

[2] IP also adjusted plant in service, accumulated depreciation and the ADIT reserve to reflect retirement of plant in service that is being replaced by the new capital additions. As shown on IP

depreciation and ADIT relating to plant in service at December 31, 2000, through September 30, 2001, is insufficient because some of the capital additions will not be placed in service until after September 30, 2001. (GCI BOE, pp. 2-5 and App. A and B[3]) As with their argument based on the adjustment for billing determinants, GCI attempt to use their argument about the depreciation reserve and ADIT reserve as grounds for limiting the capital additions to those in service at June 30, 2001. This attempt must again be rejected. At most, GCI's argument about the depreciation and ADIT reserves, if valid, would support an additional extension of the accumulated depreciation and ADIT reserves on plant in service as of December 31, 2000. In fact, however, GCI's arguments do not support <u>any</u> change to the PO's conclusion with respect to the extension of the accumulated depreciation and ADIT reserves. The adjustments for retirements and to the depreciation and ADIT reserves proposed by IP in connection with the inclusion of capital additions in rate base are fair and reasonable in the aggregate, and provide a fair and equitable matching of the post-December 31, 2000 capital additions included in rate base with post-December 31, 2000 growth in the reserves for accumulated depreciation and for ADIT.

While GCI suggest that the reserves for accumulated depreciation and for ADIT relating to plant in service at December 31, 2000 should be extended beyond September 30, 2001, GCI did not present a specific, alternative adjustment to accomplish this. Such an adjustment would

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Exhibit 2.18, p. 3 and IP Exhibit 2.19, p. 1, plant in service totaling $12,612,000 has been or will be retired due to the capital additions. In addition, as explained in IP Exhibit 1.1, pp. 12 and 13, IP also adjusted the accumulated depreciation and ADIT reserves for accumulated depreciation and deferred tax activity on the capital additions projects from their in-service dates through June 30, 2002.

[3] The replacement language in Appendices A and B to GCI's BOE appears to mis-state GCI's proposal. The replacement language to the "Commission's Conclusion" in Appendices A and B to GCI's BOE provides for the cut-off date for capital additions and for the extension of the accumulated depreciation and ADIT reserves relating to plant in service at December 31, 2000, to be <u>July</u> 30, 2001. However, GCI argue in the text of their BOE that the cut-off date should be <u>June</u> 30, 2001.

be extremely difficult if not impossible to implement because the small portion of the capital additions projects that were not completed as of September 30, 2001, were or will be completed at various dates after September 30.[4] Extension of the reserves for depreciation and ADIT relating to plant in service as of December 31, 2000 all the way through June 30, 2002 would be inequitable to IP because the capital additions adjustment approved by the PO does not include all of IP's anticipated capital additions through June 30, 2002. If all of IP's anticipated capital additions through June 30, 2002 were to be included in rate base, the size of the increase to rate base for capital additions would be much larger than the adjustment the PO has approved. (IP Ex. 2.17, p. 3; see IP Init. Br., p. 13, n. 9)

In summary, the adjustments proposed by IP and accepted by the PO relating to retirements of plant in service associated with the capital additions, accumulated depreciation and ADIT activity relating to the capital additions subsequent to their in-service dates, and accumulated depreciation and ADIT activity relating to plant in service at December 31, 2000 from January 1, 2001 through September 30, 2001, result in a fair, reasonable and equitable balancing of post-December 31, 2000 retirements and the changes in the reserves for accumulated depreciation and ADIT, with the capital additions allowed in rate base. GCI have not presented an alternative adjustment to the reserves for accumulated depreciation and ADIT that would be more consistent with the basis for the adjustment for capital additions. GCI's exceptions relating to the extension of the reserves for accumulated depreciation and for ADIT

[4] Of the total amount of energy delivery-related capital additions proposed by IP, accepted by Staff and approved by the PO for inclusion in rate base, 83.6% were actual expenditures as of September 30, 2001. (IP Ex. 2.17, p. 3) Thus, the amount of the capital additions dollars representing expenditures to be made after September 30, 2001, constitutes a relatively small portion of the total adjustment.

on plant in service at December 31, 2000, must be rejected, and the PO's conclusion on this issue should be accepted.

d. Capitalization of severance costs – Staff's Proposed Adjustment for Future Rate Cases Must Reflect Amortization of the Capitalized Severance Costs

Illinois Power does not object to the revision to the section of the PO stating "Staff's Position" with respect to the issue of capitalization of severance costs, as it results in a more complete statement of Staff's position on this issue. (See Staff BOE, p. 2)

With respect to Staff's proposed revisions to the "Commission's Conclusion" section of the PO on capitalization of severance costs, Illinois Power has taken exception to the PO's conclusion that no portion of IP's severance costs and early retirement costs should have been capitalized, for the reasons presented in IP's BOE. Assuming that the Commission were to agree (incorrectly, in IP's view) with Staff's position and the PO's conclusion that severance and early retirement costs should not be capitalized, IP agrees with Staff that $4,928,000 would be removed from rate base in this case.[5]

However, IP does not agree with the second change proposed by Staff to the "Commission's Conclusion" on capitalization of severance costs, namely, to add the following language: "The Commission . . . therefore orders IP to reflect a net rate base deduction in future

[5] If the Commission were to conclude that severance and early retirement costs should not be capitalized, this does not mean that the Commission would also have to conclude that these costs should not be recovered. The issue addressed in this section of the PO is only whether severance and early retirement costs should be capitalized. The Commission could conclude that IP should not have capitalized any portion of the severance and early retirement costs, but also conclude that these costs are recoverable in their entirety as operating expenses. The substantive question of the recoverability of severance and early retirement costs is addressed in the section of the PO on Operating Revenues and Expenses. For the reasons presented in IP's BOE, the Commission should allow the Company to recover the jurisdictional portion of the severance and early retirement expenses incurred in 2000, over a five-year amortization period.

electric DST rate cases of $4,928,000." (Staff BOE, p. 3) Staff's proposed rate base disallowance represents the removal of costs that IP capitalized in the test year to plant in service accounts. Were this amount to remain in the plant in service accounts, it would be depreciated or amortized over time, to zero, as Staff witness Hathhorn (the Staff witness on capitalization of severance costs) acknowledged during cross-examination. (Tr. 314-15) Therefore, it would be inappropriate to order that the $4,928,000 be deducted from rate base in all future electric DST rate cases, without providing for an amortization of that amount to zero. For this purpose, the Commission should order that a five-year amortization period be used, consistent with the amortization period frequently used for other one-time or unusual costs. As a result, in any future DST rate cases occurring during the five-year amortization period, the unamortized portion of the $4,928,000 amount would be deducted from rate base; and in any future DST rate cases occurring subsequent to completion of the five-year amortization period, this rate base adjustment would no longer be required.

Accordingly, if the Commission were to conclude (incorrectly) that a portion of IP's severance and early retirement costs should not have been capitalized (or that no portion of the severance and early retirement costs is recoverable), then the sentence that Staff proposes to add at the end of the "Commission's Conclusion" on Capitalization of severance costs would need to be revised to read as follows:

> The Commission orders IP to make an adjustment to its regulatory records for the $4,928,000 of capitalized severance costs, as proposed by Staff. The Commission also directs IP to amortize the $4,928,000 amount over a five-year period; during any future electric DST rate cases decided during the five-year amortization period, IP would deduct the unamortized balance of the $4,928,000 amount from rate base.

e. Deferred tax debit balances – GCI's Proposed Adjustment to the Deferred Tax Reserve Was Properly Rejected by the Proposed Order

GCI assert that "IP improperly reduced the accumulated deferred income tax ('ADIT') debit balance, thereby unfairly increasing rate base." (GCI BOE, p. 8) This assertion is incorrect. IP deducted its entire jurisdictional ADIT balance from distribution rate base (adjusted, as necessary, to reflect the impacts of other adjustments, such as additions to plant in service). Thus, there was nothing that IP had to prove was "just and reasonable" (see GCI BOE, p. 8). Further, IP is not "earn[ing] a return" on any "funds" in the ADIT balance, as GCI suggest. (GCI BOE, p. 9) IP is earning a return on the net amount of its property, plant, equipment and working capital included in rate base. The aggregate ADIT deduction serves to reduce the overall balance on which IP is allowed to earn a return. The theory behind reducing rate base by the amount of the aggregate ADIT balance is that the ADIT balance is in effect non-investor-supplied capital that supports, in a balance sheet sense, a portion of the utility's assets, and the utility should not be allowed to earn a return, through its regulated rates, on the portion of its jurisdictional assets that are not supported by investor-provided capital.[6] (IP Ex. 1.34, pp. 27-28; Tr. 412)

GCI want the Commission to engage in a process of matching individual components of the aggregate ADIT reserve against the reserves, deferred credits, deferred liabilities or other items to which they relate. (See GCI Ex. 2.0, p. 28) As noted in the PO, it has not been the Commission's practice to match up the individual components of the aggregate ADIT balances

[6] GCI note that IP did not include in the aggregate ADIT balance deducted from distribution rate base a deferred tax debit balance relating to the unamortized gain realized on the sale of IP's fossil generating plants. This ADIT amount arises from generating plants that IP no longer owns. GCI say that they are not proposing that this ADIT amount be reflected in rate base in this case. (GCI BOE, p. 8) We also presume that GCI are not suggesting that the unamortized balance of the gain should be included in distribution rate base.

against the reserves, deferred credits, deferred liabilities and other items to which they relate to determine which components of the aggregate ADIT balance should be deducted from rate base and which should not be deducted. (PO, p. 23) In fact, the Commission has previously rejected a similar proposed adjustment by GCI's witness. (See IP Init. Br., p. 34) On this basis alone, GCI's position can be rejected. In addition, Illinois Power showed that the adjustment to ADIT proposed by GCI's witness was incomplete; a complete application of his theory to the ADIT balances would result in a considerably smaller adjustment than GCI proposed. (See IP Ex. 1.63, pp. 21-22, and IP Ex. 1.69) The Commission, as the PO has done, should reject GCI's proposed adjustment to the ADIT reserve component of rate base.

3. <u>Commission's Conclusion on Rate Base</u>

In Appendix D to its BOE, GCI provide a replacement table for the Commission's Conclusion on Rate Base in the PO that purports to reflect the impacts of adopting the additional rate base adjustments proposed by GCI in its BOE. For the reasons stated above, all of GCI's exceptions to the PO's findings and conclusions as to rate base should be rejected. However, a cursory review of GCI's table shows that it cannot be an accurate representation of the impacts of adopting GCI's recommendation. For example, GCI's only recommendation with respect to the Plant in Service component of rate base is to limit capital additions to those placed in service as of June 30, 2001. However, the replacement table in Appendix D to GCI's BOE shows a $178,753,000 reduction to the plant in service amount found by the PO, even though the total amount of the capital additions to plant in service (net of related retirements) proposed by IP and accepted by the PO is $94,262,000. (This is the sum of columns (3) and (4), lines 1 through 3, on page 1 of IP Exhibit 3.24 Revised.) Since GCI are proposing only to limit capital additions to those in service as of June 30, 2001 (versus the September 30, 2001 date used in the PO), and not to eliminate them altogether, the impact of GCI's proposed adjustment on plant in service ought to be considerably smaller than $94.3 million, not almost twice as large. Further, since the Plant in Service amount as found by the PO incorporates other adjustments to IP's overall rate base, it is likely that there is some double-counting between GCI's adjustment and other adjustments accepted by the PO. In short, the rate base summary table provided in Appendix D to GCI's BOE appears to be a seriously inaccurate quantification of the impacts of GCI's proposed adjustments to rate base.

V. OPERATING REVENUES AND EXPENSES

C. Adjustments – Contested

3. Severance Costs

As detailed in IP's BOE, the PO's conclusion that IP should not be allowed to recover the jurisdictional portion of the severance and early retirement costs it incurred in 2000 is incorrect and should be rejected. However, if the Commission were to agree (erroneously) with the PO's conclusion on this issue, the technical corrections to the "Commission's Conclusion" identified at page 3 of Staff's BOE would be appropriate.

5. Functionalization of A&G Expense – IIEC's Adjustment to A&G Expenses Should Be Rejected

IIEC agrees with the PO's conclusion concerning functionalization of A&G expenses, but proposes a different adjustment to A&G expenses than the one adopted by the PO. (IIEC BOE, pp. 2-4) For the reasons detailed in IP's BOE, the PO's conclusion on functionalization of A&G expenses is arbitrary and erroneous, and must be rejected by the Commission. IIEC's proposed limitation on IP's A&G expenses is, in concept, based on the same flawed arguments and assumptions as Staff's adjustment (which the PO specifically adopts). However, even if the Commission were to agree (erroneously) with the PO's conclusion in principle, IIEC's proposed adjustment should be rejected.

IIEC terms its proposed change to the Commission's Conclusion a "correction" and states that the PO "incorrectly" used the "starting point as proposed by Staff" to calculate the adjustment to A&G expenses. (IIEC BOE, p. 3) In fact, the PO obviously intended to, and did, use the precise adjustment proposed by Staff.[7] Staff's adjustment starts with the amount of A&G expenses that the Commission allocated to distribution in the 1999 DST Case, based on application of a labor expense allocation factor, and then applies a growth factor equal to the percentage increase in distribution operating and maintenance ("O&M") expenses to arrive at the amount of A&G expenses that should be allowed in the distribution operating income statement in this case. (See Staff Ex. 21.0) IIEC's adjustment, in contrast, would start with the amount of A&G expense allocated to distribution in the 1999 DST Case less the other ratemaking adjustments adopted in the 1999 DST Case, before applying the growth factor. IIEC's proposed adjustment is flawed because it would perpetuate all of the other ratemaking adjustments to A&G expense that were made in the 1999 DST Case to this case, regardless of whether these adjustments are applicable to this case. Assuming the Commission were to erroneously conclude that a portion of IP's A&G expense must be allocated to "generation," Staff's adjustment methodology would be more appropriate because it would take the ratemaking adjustments to A&G expense adopted in this case, based on this record, directly into account in arriving at the net adjustment for allocation of A&G expense to distribution. (See Id.) IIEC's adjustment must therefore be rejected. If the Commission determines (erroneously) to make an adjustment relating to the functionalization of A&G expenses to distribution, it should use Staff's approach (as revised for the necessary corrections and updating shown in Addenda A and B to IP's BOE).

[7] As shown in IP's BOE, there were errors both in Staff's calculation of its A&G adjustment and in the PO's implementation of that adjustment.

6. Amortization Rate of Intangible Plant – The Proposed Order Correctly Rejected GCI's Adjustment to Amortization Expense

GCI contended that the amortization expense for intangible plant included in the revenue requirement should be reduced well below the test year amount. GCI asserted that their calculations indicate that IP's balance of intangible plant is likely to be fully amortized by mid-2003, and that based on recent years' additions, IP does not appear to be adding new intangible plant at a fast enough rate to offset this, with the result that "after June 2003, IP will be collecting for a higher amortization expense than justified by its current investment in intangible plant." (GCI BOE, pp. 9-13) The PO rejected GCI's proposal, for three reasons: (1) GCI's attempt to show that even with future additions, the intangible plant balance will be fully amortized, is speculative; (2) as Staff testified, the amortization rate for intangible plant should be based on the useful lives of the assets, not on the timing of the next rate case; and (3) GCI's proposal is an attempt to adjust one revenue requirement component for a development projected (by GCI) to occur well after the end of the test year, without adjusting for any other revenue requirement components that far into the future. (PO, p. 49) The PO's reasoning fully justified its rejection of GCI's proposed adjustment. GCI's exceptions to the PO's conclusion are unpersuasive and must be rejected.[8]

As to the PO's first reason for rejecting GCI's adjustment, GCI state that their proposal is predicated on the low level of IP's additions to intangible plant in 1998 through 2001, totaling $5.0 million in those years according to GCI, and "the substantially lower [according to GCI]

[8] GCI state that IP's annual amortization expense for intangible plant is $7.1 million, that the balance of intangible plant at the end of 1997 was $84.4 million, and that this balance will be fully amortized by the end of 2002, i.e., five years later. (GCI BOE, pp. 10, 11) Something about this calculation does not compute. GCI also refer to what they characterize as "the substantial and abnormal 1997 additions to intangible plant" (GCI BOE, p. 11), but GCI provide no citations to support this characterization.

indicated level of future additions." GCI also assert that there is a "relatively low level of post-test year additions to intangible plant." (GCI BOE, p. 10) However, IP's intangible plant capital additions as approved by the PO (i.e., actual expenditures, plus remaining expenditures on projects that have received funding approval from management, as of September 30, 2001) total $4,690,000. Moreover, at December 31, 2000, IP had an additional $2,545,000 of intangible plant additions that had been completed but not yet transferred on the Company's books from construction work in progress accounts to plant in service accounts. (See IP Ex. 3.24 Rev., line (3), columns (3), (4) and (7)). Thus, the known additions to intangible plant to be booked in 2001 total over $7.2 million.[9] This illustrates why the PO correctly labeled as "speculative" GCI's attempts to predict the future rate of additions to intangible plant and to predict when the balance of intangible plant will be fully amortized.

With respect to the PO's second reason for rejecting GCI's adjustment, GCI assert that "The fact that amortization is based on the useful life of the assets is irrelevant to GCI's proposed reduction in amortization for intangible plant," and that "GCI does not challenge that IP's amortization is based on the useful life of its assets." (GCI BOE, p. 11) These concessions simply underscore the correctness of the PO's reasoning and conclusion in rejecting GCI's proposal. If GCI are not disputing that IP is using proper amortization rates for intangible plant, there is no basis for requiring IP to change the amortization rate to one that would not reflect the useful lives of the underlying assets.

[9] Thus, GCI's statement in footnote 9 on page 11 that "IP has presented no evidence that the level of future additions will differ significantly from those in 1998-2000," as well as its assertion on page 12 that the current level of amortization expense "is certain not to occur during the first year of the tariff," are wrong. More generally, GCI's assertions are simply an invitation to engage in dueling speculations about events beyond 2001, which the PO properly rejected.

GCI also contend that, contrary to the second reason given by the PO for rejecting their proposal, they are not arguing that the amortization expense should be determined based on the expected timing of future rate cases. (GCI BOE, p. 12) *But that is exactly what GCI are arguing*. At the root of GCI's proposed adjustment is a belief that IP's next DST rate order will not be issued until 2005 at the earliest, with the result that for a period of 1-1/2 years (i.e.. mid 2003 to early 2005), IP's distribution rates will (according to GCI's prognostications) reflect a higher level of amortization expense than IP will be incurring. If another DST rate order for IP were anticipated sometime in 2003, this would likely be a non-issue in this case for GCI.

As to the PO's third reason for rejecting GCI's proposal, GCI contend that this reason should not be applicable to its proposal to reduce the intangible plant amortization expense because it can be predicted with reasonable certainty that the current annual expense will become too high by the end of 2002 or the middle of 2003. (GCI BOE, pp. 12-13) GCI miss the point of the PO's reasoning, which is that GCI are attempting to reach out well beyond the end of the test year (i.e., by some 24 to 30 months) to adjust the revenue requirement for only a single cost element that GCI expect to decrease in that time frame. For example, it can be stated with a high degree of certainty that other expense components will increase for IP in 2002 and 2003, and that IP will continue to make additions to its plant in service, if for no other reason than to replace worn out facilities and equipment that were installed many years ago at much lower costs than the equipment that will be installed to replace it. However, it will be the overall impact of all of the changes to IP's revenue requirement in 2003 and thereafter that will determine whether IP's DST rates continue to be just and reasonable.

GCI state that "IP has not provided any future expense estimate to support a continued collection at" the current rate of amortization expense for intangible plant. (GCI BOE, p. 12) IP has not presented any such future expense estimates because the period on which GCI focus – the end of 2002, the middle of 2003 and beyond – is well beyond the end point for any adjustments that this Commission would conceivably consider in setting DST rates in this case based on a 2000 test year. Moreover, if IP were to provide future expense estimates for the late 2002 – 2003 time frame for its intangible plant additions, retirements and amortization expense, then IP should also be allowed to present projections, and have considered for inclusion in the rates set in this case, estimates of its plant additions, increased O&M expenses, and other cost changes in that time frame. GCI would be the first to object to such an attempt.

As the foregoing discussion illustrates, GCI's proposal to reduce the amortization rate for intangible plant based on projected future events is essentially single-issue ratemaking, and was properly rejected by the PO.

7. Injuries and Damages Expense – The Rate Base Adjustment Proposed by GCI for Future Cases is Inappropriate

GCI do not take exception to the PO's acceptance of IP's proposal to amortize, over three years, a $5.5 million expense that IP recorded in 2000, in accordance with Statement of Financial Accounting Standards ("SFAS") No. 5, Accounting for Contingencies, for pending litigation claims against it. (See IP Init. Br., pp. 71-73; IP Ex. 1.34, pp. 65-67) However, GCI contend that the Order in this case should state that in future rate cases, there should be a rate base deduction for this accrued liability in excess of the amount of claims actually paid. (GCI BOE, p. 13) There is no basis for including such a requirement in this Order. The $5.5 million expense recorded in 2000 for these three claims was a current period expense that IP was required to record in that year in accordance with SFAS 5, as GCI's witness acknowledged. (IP Ex. 1.34, p. 66; Tr. 414-19) IP proposed to amortize this particular injuries and damages expense over three years because it was an unusually large expense item and resulted in the aggregate test year injuries and damages expense being atypically high. However, to make a rate base deduction in a future rate case because the actual payments exceeded the estimated amount of the loss (i.e., the expense) recorded in 2000 would be a form of retroactive ratemaking.[10] Further, GCI have not proposed that IP should be entitled to a rate base increase if the ultimate payments on these claims exceed the amount of the expense recorded in 2000. GCI's exception on this issue should be rejected.

VI. COST OF CAPITAL

Illinois Power agrees with the correction to the Cost of Capital section of the PO that Staff proposes at page 4 of its BOE.

VII. COST OF SERVICE; RATE DESIGN; OTHER TARIFF ISSUES

B. Allocation of Miscellaneous Revenues to Customer Classes – The Proposed Order Correctly Rejected GCI's Alternative Allocation as Incomplete and Incorrect

The PO accepts the allocation of miscellaneous revenues to the DST customer classes as provided in IP's embedded cost of service study ("ECOSS"), and rejects the allocation of miscellaneous revenues proposed by GCI witness Smith. (PO, p. 57) GCI take issue with the PO's conclusion. (GCI BOE, pp. 13-15) However, GCI's proposed allocation of miscellaneous revenues is properly rejected on several grounds. First, the basis for GCI's allocation of the miscellaneous revenues is at best unexplained in the record. Second, as to those components of miscellaneous revenues for which GCI do provide an explanation, GCI's approach is either the same as IP's approach, or substantively wrong.

[10] Expenses are often recorded on an accrual basis, particularly at the end of a year. The recorded expense for the period is not subsequently reduced for ratemaking purposes because it turns out, in a subsequent period, that the actual expense was less than the accrual recorded.

GCI witness Smith stated unequivocally in her direct testimony that "I have allocated all of the miscellaneous revenues on the same basis as the Distribution Operating Labor expense." (GCI Ex. 1, p. 9) Essentially the same statement was made in Section IV.B of GCI's Initial Brief. There is no basis for allocating all of the miscellaneous revenues (which includes such components as forfeited discounts (late payment charges) and service activation fees) to the customer classes on the same basis as the allocation of Distribution Operating Labor Expense. On these grounds alone, GCI's allocation of miscellaneous revenues should be rejected.

GCI now belatedly suggest in their BOE that there may have been "confusion" and that GCI witness Smith did not in fact allocate all miscellaneous revenues on the same basis as Distribution Operating Labor Expense. (GCI BOE, p. 14) Even if this is true, the fact remains that nowhere in GCI witness Smith's direct or rebuttal testimony or exhibits is there an exhibit or table showing GCI witness Smith's allocation of the various categories of miscellaneous revenues to the customer classes, or a narrative explanation of how she allocated the various categories of miscellaneous revenues to the customer classes. GCI assert that "GCI Witness Smith's Direct and Rebuttal Testimony clearly demonstrate GCI's methodology of allocating all miscellaneous revenue," and then provide a garbled citation (GCI BOE, p. 14), but a review of GCI witness Smith's direct and rebuttal testimonies (GCI Ex. 1 and 3) shows that this assertion is incorrect. In contrast, IP cost of service witness Karen Althoff presented testimony and an exhibit that explained the bases on which IP allocated the various categories of miscellaneous revenues to the customer classes, and that showed the specific allocation of each category of miscellaneous revenues to the customer classes. (IP Ex. 8.10, pp. 5-7; IP Ex. 8.12) On this basis alone, the Commission should reject GCI's proposed allocation of miscellaneous revenues to the customer classes, and accept IP's allocation.[11]

Third, with respect to the one category of miscellaneous revenues that GCI's witness did discuss at some length, equipment rentals, the PO correctly rejected GCI's allocation method as inferior to IP's allocation method. GCI argue that these miscellaneous revenues should be allocated on the same basis as the underlying equipment expenses. (GCI BOE, p. 15) GCI witness Smith had contended that a portion of equipment rental revenues should be allocated to the residential class because the costs of IP's equipment, including the equipment that IP rents to customers (such as transformers and substations), are allocated to the residential class. (GCI Ex. 1, pp. 7-8; GCI Ex. 3, pp. 1-2) This is incomplete reasoning. The costs of 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) This produces a fair allocation of the underlying plant investments and expenses, which GCI witness Smith did not challenge. Each class' rates must then be set to recover the portion of the overall cost of service that has been allocated to the class. The non-residential classes (in particular the demand-metered classes), however, make a contribution to recovery of their allocated share of these costs through the payment of rental revenues for equipment. (Tr. 517) 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 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

[11] GCI also state that for at least some categories of miscellaneous revenues, GCI used the same allocation method as the Company. (GCI BOE, p. 14) GCI should have no issue with the PO's acceptance of IP's allocation method for those categories.

requirement responsibility that must be recovered through the base distribution rates. GCI's allocation of equipment rental revenues ignores these principles, and was properly rejected by the PO.

C. Meters and Service Drop Issues – The PO Properly Rejected IIEC's Arguments to Set Charges for the Demand-Metered Class on a Basis Other Than Cost of Service

During the course of this case, IIEC contended that IP's proposed metering charges reflected an excessive allocation of G&I plant and A&G expenses to the metering function. Illinois Power showed that it had allocated G&I plant and A&G expenses to the metering function using the same methodology that was approved in the setting of the initial unbundled metering charges in the meter unbundling case, Docket 99-0013, i.e., based on the relationship of meter service labor to total electric distribution labor. IIEC's witness did not provide any alternative approach, and did not dispute the fact that IP allocated G&I plant and A&G expense to the metering function in the same manner as approved in Docket 99-0013. (See IP Init. Br., pp. 81-82) Consistent with this record, the PO concludes that "the record indicates that IP allocated such costs consistent with the approach approved by the Commission in Docket 99-0013. . . The Commission finds IP's method for establishing metering charges to be consistent with the method approved in Docket 99-0013 and reasonable for setting rates in this proceeding." (PO, p. 60) Although IIEC, in its BOE, continues to grumble about the metering cost study (IIEC BOE, pp. 4-5), IIEC again fails to refute the fact that IP allocated G&I plant and A&G expense to the metering function using the same methodology that the Commission approved in Docket 99-0013, or to suggest any alternative allocation approach.[12]

[12] The Staff cost of service/rate design witness proposed the same metering charges as did IP, for both the small use general service and demand-metered classes. (See Staff Ex. 22.0, Sched. 14.4 Rev. and 14.5 Rev.)

Instead, IIEC now asserts that because the PO does not direct IP to re-run its ECOSS based on the final approved revenue requirement in this case, and to use those ECOSS results as the basis for setting the final rates and charges, the Commission should direct that all charges for the demand-metered DST class should be increased on an equal percentage basis.[13] (IIEC BOE, p. 5) IIEC is simply trying to avoid the results of IP's ECOSS for rate design purposes and instead obtain equal percentage increases for all charges to the demand-metered class. The PO elsewhere rejects IIEC's proposal for a non-cost-based equal percentage increase in charges to the demand-metered class (see PO, p. 79, 80), and IIEC's new argument concerning the metering cost study does not provide a basis for changing the PO's conclusion.

D. Residential and Small Use General Service Charges

Residential Delivery Charge – Staff's Proposed Flat Rate is Unjustified on Both Cost of Service and Rate Continuity Grounds

The PO rejected IP's proposal to establish a two-block residential delivery charge in SC 110 with a 1.4 cent/kWh differential between the blocks, and instead adopted GCI's proposal to set the differential between the blocks at 0.8 cents/kWh. (PO, p. 68) IP has taken exception to this conclusion. (See IP BOE, pp. 67-69) In reaching this conclusion, the PO also rejected Staff's proposal for a flat residential delivery charge in SC 110. (PO, p. 68) Staff has taken exception to this conclusion, and continues to contend that the Commission should establish a flat residential delivery charge. (Staff BOE, pp. 4-8) Staff's exception must be rejected. The record does not support Staff's position that the residential delivery charge should be flat.

[13] IP would be willing to re-run the ECOSS based on the revenue requirement approved in the final Order in this case, and to circulate the revised ECOSS results to Staff and other parties for use in reviewing IP's compliance tariff filing. IP estimates that it would take two business days to re-run the ECOSS following receipt of the final Order.

The principal reason that the Commission must reject Staff's proposal for a flat residential delivery charge is that it is not justified on cost of service grounds. Staff's assertion that secondary facilities costs "are incurred to meet the maximum demands expected for customers" (Staff BOE, p. 6) is incomplete. The record shows that secondary distribution facilities are incurred *primarily as a function of connecting the customer to the system*, regardless of the customer's actual load.[14] (IP Ex. 6.6, p. 9; IP Ex. 6.14, pp. 7-8) In other words, secondary facilities costs have a significant customer component, and a relatively small usage-sensitive component. (See IP Init. Br., pp. 83-86) This fact is illustrated by IP Exhibit 6.12 Revised, which shows that the cost of secondary facilities to serve a group of customers using 3,000 kWh per month are less than two times the costs of the secondary facilities to serve a group of customers using 300 kWh per month (i.e., using only one-tenth the kWh as the first group). Therefore, a significant portion, if not all, of the cost of secondary distribution facilities should be recovered in an initial block of the delivery charge. Thus, while there can be room for debate over how much of the secondary facilities costs should be recovered in the first block (i.e., what the differential between the first and second blocks should be), there is absolutely no justification for recovering these costs over the entire range of consumption, through a flat delivery charge. Staff's assertion that "Staff's flat rate proposal is more cost-based because it would recover these costs [of secondary facilities] over all kWhs of delivery service" (Staff BOE, p. 6) is unsupported by the facts.

Staff also disputes the PO's conclusion that the objectives of maintaining continuity and consistency between the residential energy charge in the principal residential bundled tariff, SC

[14] As illustrated by IP Exhibit 6.12 Revised, secondary facilities consist of secondary lines, transformers and service lines. For example, every residential customer must have a service line in place regardless of the customer's usage.

2, and the residential delivery charge in SC 110, are important goals as residential customers become eligible for delivery services. (PO, p. 68; see Staff BOE, pp. 4-5) Staff asserts that there is no need to attempt to maintain consistency and continuity with a bundled rate that was last set by the Commission a decade ago. (Staff BOE, p. 5) However, Staff apparently did not have this concern when it unequivocally agreed that the residential DST facilities charges should be set equal to the facilities charges in the principal residential bundled rate, even though the residential bundled facilities charges were last set by the Commission a decade ago. In addition, Staff is off base when it asserts that when the declining block energy charge in SC 2 was set, IP was "wrestl[ing] with the problem of excess capacity" and that the declining block charge was set "to stimulate demand and thereby bring supply and demand into balance." (Id.) At the time IP's bundled rates were last set, in Docket 91-0335, IP's nuclear plant had already been declared fully "used and useful" by the Commission based on its "reserve margin" test. (Order in Docket 91-0147 (Feb. 11, 1992), p. 15) Further, there is no basis in the Order in Docket 91-0335 (and Staff has cited none) to support Staff's assertion that the declining block energy charge was established "as a means to stimulate demand." (Staff BOE, p. 5) In fact, the Order in Docket 91-0335 states that the residential tailblock energy charge that the Commission approved "reflects economically efficient pricing." (Order in Docket 91-0335 (July 8, 1992), p. 51)

In any event, customers do not know or care why or when the current bundled energy charge was established as a declining, two-block rate with the first block at 300 kWh per month; they would only be given pause, as they considered switching to delivery services, if they saw a different rate structure in the DST rates than in the bundled rates. This is precisely why the PO correctly states that "the Commission believes that, at this time, it is important to maintain some consistency between the bundled residential rates and the residential delivery service rates."[15] (PO, p. 68)

Staff's real agenda is to set a flat delivery charge in SC 110 because Staff believes it will promote conservation in electricity usage. (Staff BOE, pp. 5, 6) The value of trying to encourage conservation in electricity usage through the design of the SC 110 delivery charge, which will be a small portion of the DST customer's total bill, and much less significant than the power and energy portion of the customer's bill, is highly questionable. It is also highly questionable whether the small difference between IP's proposed residential tailblock delivery charge and Staff's proposed flat delivery charge, less than 0.5 cents/kWh, would provide any sort of meaningful conservation signal to residential DST customers. (See IP Init. Br., p. 84) In any event, Staff and IP can agree that "[i]t is particularly important that the inauguration of residential delivery services rates be based on the proper cost of service footing." (Staff BOE, p. 6) As shown above, however, a two-block, declining residential delivery charge, as proposed by IP and GCI and approved by the PO, represents the "proper cost of service footing." A flat delivery charge does not.[16] Cost-based rates provide the most appropriate price signals (IP Ex.

[15] Staff also asserts that "the Commission did not feel bound by the bundled rate precedent when it approved a flat delivery charge for Small Use General Service customers in Docket No. 99-0117" (which was ComEd's initial DST case; we assume Staff was intending to refer to IP's 1999 DST Case). (Staff BOE, p. 5) In the context of the initial DST case (which was conducted in only six months), with so many issues to be addressed with respect to determining an unbundled distribution revenue requirement and establishing all the terms and conditions for delivery services, it is not surprising that some rate design issues received short shrift. However, in this case, IP has proposed to set the small use general service delivery charge in SC 110 as a two-block rate, and the PO has agreed with IP's proposal. (PO, p. 68)

[16] In support of its position, Staff cites various arguments that were made by GCI. (Staff BOE, p. 7) However, GCI have not taken exception to the PO's conclusion that the residential delivery charge in SC 110 should be a two-step, declining block rate.

6.6, p. 8); attempting to promote conservation by implementing charges that do not reflect cost of service is an inappropriate objective.

In sum, the PO correctly rejected Staff's arguments for a flat residential delivery charge in SC 110, and the Commission should reject Staff's exceptions to this conclusion.

Small Use General Service Delivery Charge – Staff's Proposed Flat Rate is Unjustified on Both Cost of Service and Rate Continuity Grounds

Staff also takes exception to the PO's conclusion that the small use general service delivery charge should be a two-block declining structure. (PO, p. 68; Staff BOE, pp. 8-9) Staff relies on the same arguments it makes with respect to the residential delivery charge, plus one additional argument. The Commission should find Staff's arguments for a flat delivery charge no more persuasive with respect to the small use general service delivery charge than they are with respect to the residential delivery charge. Indeed, the cost of service basis for the two-block structure is even stronger for the small use general service class than it is for the residential class. (See IP Init. Br., pp. 87-88)

The one additional argument advanced by Staff is that rate continuity is not as much of a consideration for the small use general service class because the present delivery charge for this class in SC 110 is a flat rate. (Staff BOE, p. 9) However, while the delivery charge in present SC 110 for the small use general service customers is flat, the energy charge in the <u>bundled</u> rate for small use general service customers, SC 10, has a declining block structure, not a flat structure. In light of the fact that very few small use general service customers have switched to delivery services at this time, maintaining rate continuity from the current bundled rate to the delivery service rate for this class is a more important consideration than maintaining rate continuity between the delivery charge currently in SC 110 for this class and the delivery charge adopted in this case. (Tr. 806-07, 871-72) Thus, IP's proposed rate design for the small use general service delivery charge is superior to Staff's proposed rate design on rate continuity and consistency grounds as well as on cost of service grounds. The PO appropriately rejected Staff's proposal and accepted IP's proposal, and the Commission should do the same.

E. Demand Metered General Service

1. Transformation Charges – The Proposed Order Correctly Concluded that the Current Transformation Charges in SC 110 Should Remain in Place

In this case, IP has not proposed any changes to its transformation charges. 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, where IP provides transformation for the customer. IIEC questioned the higher transformation charge for the larger (3 MW and above) customers. IIEC proposed 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. (IIEC Ex. 1, pp. 21-23) IP's bundled tariffs currently include transformation charges of 75 cents per kW for all demand-metered customers, both those above 3 MW and those below 3 MW. (IP Ex. 6.6, p. 16) The PO rejects IIEC's arguments and concludes that the transformation charges in SC 110 should remain at their current levels. IIEC takes exception to the PO's conclusion. IIEC argues that either the transformation charge for DST customers under 3 MW should be increased from 50 cents/kW to 75 cents/kW (even though IP has not proposed to impose a rate increase on these customers), or, alternatively, that the transformation charge for DST customers above 3 MW should be reduced from 75 cents per kW to 50 cents per kW, so that it will be 33% below the comparable charge applicable to similarly-sized bundled service customers. (IIEC BOE, pp. 5-10) The Commission should reject IIEC's exceptions and adopt the PO's conclusion on this issue.

Demand-metered customers have the option either to take transformation service from IP, or to rent or install their own transformation facilities. Accordingly, the transformation charge is based 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) Moreover, transformation charge revenues serve to reduce the class revenue requirement that must be recovered through demand charges. (IP Ex. 6.6, p. 16) The current transformation charge in SC 110 of 75 cents per kW for customers 3 MW and larger is within the range of the costs of recently installed transformation facilities. (Id.; IP Ex. 6.10, Sched. 2, item 4). Further, due to the fact that transformation facilities for customers 3 MW and larger 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 own transformation facilities.[17] (IP Ex. 6.6, pp. 16-17; IP Ex. 6.14, pp. 15-16)

IIEC asserts that "IP has not met its burden in substantiating its cost proposal for transformation charges." (IIEC BOE, p. 6; see also Id., p. 9) However, IP has not made any cost proposal for transformation charges – IP did not file tariff sheets in this proceeding to change the transformation charges in SC 110. Indeed, the current transformation charge in SC 110 for customers above 3 MW was only recently established, in a separate filing subsequent to issuance of the 1999 DST Order. (IP Ex. 5.11, p. 13) Since IP has not proposed to change the current SC 110 transformation charges and it is IIEC that is seeking to change these charges, the burden of proof must fall on IIEC, as it would in a complaint case.

IIEC contends that the evidence does not support the proposition that the 75 cents per kW charge for customers 3 MW and above is within the range of cost for recently-installed

[17] Of 73 IP customers 3 MW or larger, 57 already rent or own their own transformation facilities. (IP Ex. 6.6., p. 16)

transformation facilities. (IIEC BOE, pp. 6-8) IIEC's arguments and calculations on this point appear to be based on the fact that in the portion of IP Exhibit 6.10 Revised that shows the costs of recent substation installations for customers 3 MW, IP included a customer whose transformer had a rating of 2.975 MW; IIEC has excluded this customer from its calculations for the "3 MW and above" group. As footnote (3) on the exhibit shows, 2,975 kW was the rating on the customer's transformer, not the customer's demand. This particular installation was appropriately included in the list of recently-completed substation installations for customers 3 MW and above. Further, as IP witness Jones explained, customers with demands 3 MW and above typically require substations to transform their power (IP Ex. 6.6, p. 17); thus, the costs for the five recently-installed substations define an appropriate range for the transformation charge for customers 3 MW and larger. Accordingly, the range of the costs of installed equipment for the five recently-installed substations and related facilities for IP customers 3 MW and above, depicted on IP Exhibit 6.10 Revised, is from 43 cents per kW to 97 cents per kW. (See Rev. IP Ex. 6.10, Sched. 2, Item 4) Thus, the currently-effective transformation charge of 75 cents per kW is in fact within the range of costs for recently-installed substation and related facilities for customers 3 MW and above, IIEC's efforts at recalculating the data notwithstanding.

IIEC also notes that IP stated in a data request response that the embedded cost of transformation for the entire IP system is $1.12 per kW. (IIEC BOE, p. 8) However, 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) 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 that IIEC is attacking. (Id., pp. 16-17) IIEC also notes that in the 1999 DST Case, IP indicated that the embedded cost of transformation on its system was 42 cents per kW. (IIEC BOE, p. 9) However, the 42 cent per kW figure was the embedded cost only for line transformers installed on the IP system. 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 entire IP system. (Tr. 877-78) In any event neither of these system-wide average cost figures is relevant to determining the appropriate charge for transformation facilities specifically installed to serve demand-metered customers 3 MW and above.

In considering this issue the Commission must keep in mind that 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, in addition to taking the tariffed transformation service from IP. Further, the costs of facilities installations to provide transformation service to customers 3 MW and above can vary widely from customer to customer, based on each customer's particular requirements. Thus, basing the transformation charge on the range of current costs for IP to install transformation facilities for such customers 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. If IP were required to provide tariffed transformation service to 3 MW and above customers who elect to obtain that service from the Company, at a price below the cost of installing the required facilities (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 3 MW and above customers that elect to obtain tariffed transformation service from IP. (IP Ex.6.6, p. 17) The Commission should not countenance such a result given that these customers have competitive options for transformation facilities and service. Moreover, any 3 MW and above customers that believe the tariffed charge of 75 cents per kW is too high have the ability to obtain transformation by purchasing or leasing the necessary facilities.

In summary, tariffed transformation service for demand-metered SC 110 customers 3 MW and above is currently appropriately priced based on cost considerations as well as the fact that the current charge in SC 110 for these customers is identical to the charge in the comparable bundled tariffs. IP is not proposing any changes to the pricing of this service in this case. The PO correctly rejected IIEC's efforts to change the transformation charges in SC 110, and the Commission should do the same.

2. Demand Charges and Distribution Capacity Charges – The PO Properly Rejected IIEC's Arguments for a Non-Cost-Based, Equal Percentage Increase for Charges to the Demand-Metered Class

IIEC contends that there may be problems with the ECOSS presented by IP in its rebuttal testimony. However, IIEC does not identify any specific problems in the ECOSS that need to be revised. Although IIEC believes that the ECOSS is sufficiently accurate to be used to allocate the total revenue requirement among the customer classes, IIEC contends that the ECOSS is not sufficiently reliable to be used in setting the individual rates and charges for the demand-metered class. Accordingly, IIEC again proposes that the rate elements in SC 110 for demand-metered customers (other than the reactive demand charge, as to which the parties have agreed to a charge of 13 cents per kVar) should be increased on an equal percentage basis, rather than adjusted on the basis of cost of service. (IIEC BOE, pp. 10-12) However, the PO correctly rejected IIEC's proposal for non-cost-based rates, noting that "it cannot simply ignore the cost of service study provided by IP given that no substantive errors or problems have been identified." (PO, p. 79)

The Commission should note that despite IIEC's complaints about the difficulties it purportedly encountered in reviewing and analyzing IP's cost of service studies, both Staff and GCI were able to review IP's ECOSS sufficiently to determine that it was acceptable for use for both revenue allocation and rate design purposes (subject, in GCI's case, to the specific change they proposed regarding allocation of miscellaneous revenues). In fact, Staff prepared and presented a complete set of proposed charges for all DST rate classes, using IP's ECOSS as a starting point. (See Staff Ex. 14.0, Sched. 14.1-14.2, and Staff Ex. 22.0, Sched. 14.3 Rev., 14.4 Rev. and 14.5 Rev.) It is not credible that IIEC, with the vast resources and expertise of its consultant, Brubaker & Associates, Inc., at its disposal, was unable to review IP's ECOSS sufficiently to either find it acceptable for rate design purposes (as well as for revenue allocation purposes) or to identify specific deficiencies and errors which, if corrected, would render the ECOSS acceptable. The conclusion the Commission should draw is that IIEC does not like the results that are generated by use of IP's ECOSS for rate design purposes, but cannot find any specific changes to propose that would improve the outcome from IIEC's perspective – so it has instead raised a number of irrelevant side arguments for ignoring the ECOSS for purposes of setting specific DST rates for the demand-metered class. The Commission, like the PO, should reject IIEC's attempt to have the charges for demand-metered customers set on a non-cost of service-based, "across the board" basis in this case, when there is an acceptable embedded cost of service study available to use in designing rates.

3. Facilities Charges -- The PO Properly Rejected IIEC's Arguments for a Non-Cost-Based, Equal Percentage Increase for Charges to the Demand-Metered Class

On the same grounds it advanced with respect to demand charges for the demand-metered class (discussed in the immediately preceding section of this brief), IIEC also argues that facilities charges for the demand-metered class should be increased on an equal percentage basis, rather than on the basis of the embedded cost of service study. (IIEC BOE, pp. 12-13) The PO rejected IIEC's arguments and proposal for the same reasons that it rejected them with respect to the demand charges (PO, p. 80), and the Commission should do so too.

M. Other Tariff Terms and Conditions -- IIEC's Continued Attempts to Create Discriminatory Terms for the Benefit of a Few IIEC Members Should Be Rejected

IIEC continues to seek more favorable treatment for a few of its customers, not with respect to IP's DSTs but rather with respect to IP's bundled tariffs. (IIEC BOE, pp. 13-18) The PO properly rejected IIEC's attempts (PO, p. 122). IIEC's BOE provides no justification for changing the PO's conclusion.

The PO recognized that, regardless of the way IIEC attempted to characterize its changes, IIEC's proposals would require the Commission to order changes in IP's bundled tariffs in this DST case. (Id.) The PO also recognized that on balance, IIEC's proposals would "result in treating similarly situated customers differently and unfairly." (Id.) Rather than focus on these deficiencies, IIEC adopts a strategy of attempting to cast aspersions on IP and to craft examples where, it contends, no discrimination is present. (IIEC BOE, pp. 13-18) However, even cursory examination shows that IIEC's arguments do not support its untenable position.

First, IIEC complains about the pace of competition in IP's territory. (Id., pp. 12-13). However, as IIEC has admitted, there are a variety of reasons for the current level of competition. (IIEC Init. Br., p. 36). Although many of these reasons are beyond IP's or this

Commission's control, IIEC misses the whole point: making bundled service even more attractive (e.g., by re-opening closed tariffs or making it easier for delivery services customers to return to IP's bundled tariffs) will do little to increase the number of customers taking delivery services. In fact, it might even decrease that number, because the increased attractiveness of IP's bundled tariffs that would result from adopting IIEC's proposals will make customers more likely to choose bundled rates -- the very outcome IIEC purports to be against.

Along these same lines, IIEC dredges up an old letter sent by Chairman Mathias to IP in an attempt to support its position. (IIEC BOE, p. 17) As with so much else in IIEC's arguments, it fails to tell the whole story. IIEC does not indicate in its BOE that the letter was sent almost 2 years ago. (See Tr. 608) IIEC also fails to note that "Illinois Power changed its policy with regard to the SC 24 cancellation provisions after this letter was issued by the Chairman. In fact, Illinois Power looked at a lot of issues that were raised in this regard and tried to encourage competition in its territory."[18] (Tr. 633-34)

Second, IIEC continues to assert that because IP has shown a willingness to voluntarily make changes to its bundled tariffs in the past, it should be willing to continue to do so now. Indeed, IIEC attempts to bootstrap the fact that IP has *voluntarily* made changes to its bundled tariffs to accommodate IIEC's desires in the past, to the basis for an argument that the Commission should *order* IP to make additional changes to its bundled tariffs in this case. (IIEC BOE, pp. 16-17). IIEC's disingenuous tactics, of course, leave IP (and we suspect all other Illinois electric utilities) wondering why they should ever engage in negotiated solutions with IIEC again. Leaving aside the unfair and discriminatory effect of IIEC's proposed changes (to

[18] The ALJ ruled that the Chairman Mathias letter was not admissible, and IIEC did not take an interlocutory appeal of that ruling, so IIEC's reliance on the letter as part of its argument is at least contrary to the spirit of the ALJ's ruling.

which we turn below), IIEC is missing the point: IP has not proposed to make any changes to its bundled service classifications in this case, and IP is not willing to do so now. Rather, it is IIEC that seeks to expand the scope of this case beyond what it lawfully is: a delivery services tariff case.[19]

Third, IIEC provides hypotheticals purporting to show that its proposals are not unfair and discriminatory. However, even using IIEC's hypotheticals, the problems noted by the PO and IP are readily apparent. Take, for example, IIEC's hypothetical of an SC 24 customer who has completed its five-year primary term and now chooses to leave SC 24 and take delivery services. (IIEC BOE, pp. 14-15) Rather than compare this customer to a customer that has actually been on IP's system for five years (e.g., an SC 21 customer who has been on SC 21 for five years or an SC 24 customer who, after having been on SC 24 for five years, chooses to take service under SC 21 and later desires to return to SC 24), IIEC chooses to compare this customer to a *brand new customer*. Of course, under the contrived comparison made by IIEC, differently situated customers are treated differently. But, IIEC never explains why its proposal is fair for those customers who in fact are similarly situated. The same problems exist with respect to IIEC's SC 30/Rider S example.

In the same vein, IIEC coyly casts its hypothetical as involving a "customer that leaves IP's system and takes delivery services" (IIEC BOE, p. 15). But, under IIEC's proposal, a customer could take PPO service (i.e., continue to take electric power and energy from IP) and

[19]Equally disingenuous is IIEC's attempt to claim that it merely seeks to change IP's DSTs. (IIEC BOE, p. 13) Every provision it seeks to change is (and has been long before there were DSTs) contained in IP's bundled tariffs. IIEC's semantics only serve to underscore the discriminatory nature of its proposals: it seeks to change the rules regarding departure from and return to bundled tariffs to benefit a few customers, to the detriment of all those customers who have already made choices under IP's longstanding tariff policies and provisions in this area.

receive the benefits of IIEC's proposal, yet a customer who chooses to convert to SC 21 service (i.e., continue to take power and energy from IP) would not. IIEC's attempt to distinguish those who choose to convert from one bundled status to another from those taking delivery services fares no better. (IIEC BOE, pp. 14-15). The same factors suggested by IIEC that could lead such a customer to wish to undo its decisions (reopening of a shuttered plant whose closing led to the initial rate shift, or economic reasons) are just as likely to change as the reasons a customer would choose to return to bundled service from delivery service (economic reasons).

Finally, IIEC continues to believe that "there is no good reason why SC 21 customers" should be treated differently than SC 24 customers. (IIEC BOE, p. 17). We previously recounted the numerous very good reasons that this disparate treatment is appropriate (IP Init. Br., pp. 124-28; IP Reply Br., pp. 91-94). Rather than repeat all of them here, we note that IIEC has failed to refute any of them. We must, however, correct IIEC's description of the primary term requirement for SC 21 customers. (IIEC BOE, p. 15) Although it is possible for a new customer (or an existing customer who is adding load) to have a Primary Term under SC 21 that is as long as 3-5 years, IIEC ignores the fact that SC 21 applies these longer Primary Terms only to specific situations (e.g., when the "new" SC 21 customer was not previously taking service "under any other of Utility's service classifications" or when the added load is above a certain size, see SC 21 §§ 4(a) & (b), respectively). Of course, with respect to the former situation mentioned in the parenthetical, most customers grow to a size that makes SC 21 appropriate (and thus they have been on other IP service classifications prior to taking SC 21); they do not spring fully formed from the brow of Zeus as SC 21 customers.

In sum, IIEC's arguments for changing IP's bundled tariffs do not survive scrutiny, were properly rejected by the PO and should be rejected by the Commission in its final Order.

N. Uncontested Issues

8. Use of Electronic Signatures for Customers – RES Letters of Agency: Workshops Are the Appropriate Forum for All Issues Relating to Electronic Signatures Including Interpretation of Statutes other than the PUA

The PO adopts a process by which the parties can resolve the issues relating to the use of electronic signatures. (PO, p. 127) Now, Staff (Staff BOE, pp. 9-19) and GCI (GCI BOE, pp. 15-17) seek to have the Commission issue an advisory opinion on the legality of electronic signatures in a vacuum, *before* the parties have conducted workshops and *before* the Commission has any facts on the types of processes the parties have in mind for implementing electronic signatures.

Despite the lengthy exegeses of both Staff and GCI, neither is able to determine conclusively whether the state statute (5 ILCS 175/1-101, *et seq*.) or the federal statute (15 U.S.C. § 7001, *et seq*.) concerning use of electronic signatures applies to the situation at hand. This is not surprising because both statutes are relatively new and untested. Nor is it surprising that neither of these parties addresses the myriad questions that call for a legal interpretation based on concrete facts because, in fact, no one knows yet exactly what processes and procedures will be developed by the interested parties in a workshop process.[20] What *is* surprising is the attempt by these parties to have the Commission opine, in a vacuum, on a statute that this Commission is not even charged with implementing.[21] Whether electronic signatures will be a legal method for signing letters of agency will depend not only on the language of the

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[20]For example, neither Staff nor GCI address such issues as how all concerned will determine what constitutes a "qualified security procedure" under 5 ILCS 175/10-110 (assuming state law applies in the first instance) particularly when, for example, a RES is relying on an agreement of the parties for that very point (see subsection (a) of §10-110).

[21]Under the state statute, the Secretary of State has authority to certify various security procedures relating to electronic signatures. (5 ILCS 175/10-135)

various potentially relevant statutes, but also on the processes proposed by various parties and a careful review of those proposals against the applicable laws.

Illinois Power reiterates that it is not opposed to electronic signatures as an abstract matter. We continue, however, to be concerned with what appears to be a rush into uncharted waters. Staff's push to have all of the questions answered by May 1, 2002 (though laudable) is unrealistic given how many questions remain unanswered (and possibly even unasked). A workshop process holds the promise of resolving all of the issues relating to electronic signatures as a whole and thereby allowing the Commission to be presented with a complete package on this topic, rather than attempting to adopt an advisory legal conclusion based on what can only be generously described as a limited record. We reiterate also our commitment to work with Staff and all interested parties in workshops to resolve these issues in as expeditious a manner as possible.

In sum, Staff's and GCI's exceptions on the topic of electronic signatures should be rejected.

MEA's Transition Proposal Should be Rejected as Unsupported by the Record and Unnecessary

MEA, which intervened in this case after the record was marked "heard and taken", and did not file an initial or reply brief, has filed a BOE raising an issue that no other party has raised throughout this lengthy case. MEA's issue is based on a concern that, while potentially legitimate in other contexts, in invalid in this case. (MEA BOE, pp. 1-5) In particular, MEA seeks (without citing any support in the record for its proposal or for its factual assertions) to have the Commission order an open season to permit customers an opportunity to change their service from delivery services to bundled tariffs or from PPO service to third party service despite tariff-based contract terms. MEA bases its argument on an inapposite analogy to a non-

DST case involving another utility. Neither the record in this case nor the case relied on by MEA supports its position.

MEA bases the putative need for its transition alternatives on the claim that, based on the final order in this case, the compliance tariffs filed by IP may "result *in energy prices* that are more costly than bundled services from IPC or service available from [a RES]." (MEA BOE, p. 2) (emphasis supplied) As a latecomer to this docket, MEA obviously is unaware that this case will not affect any customer's power supply contract with a RES, and that the changes that IP is proposing to Rider PPO in this case (all but one of which are uncontested) will have at most a minor impact on the overall charges paid by a Rider PPO customer.[22] Even if one were to give MEA the benefit of the doubt and assume that it meant the new delivery service rates to be determined by this case might affect a customer's decision to take delivery services instead of bundled service, there remains no reason to facilitate a transition between PPO and third party supply, because the customer pays the same delivery charges in either instance. More importantly, although the record was not developed with this new issue in mind, what little there is in the record counsels against the need for a transition for any customer group. In particular, the actual energy charges a customer faces are orders of magnitude higher than the changes IP has proposed for its delivery charges. (See IP Ex. 5.12, p. 9) Thus, the idea that the change in delivery rates approved in this case will alter a customer's decision to stay on delivery services ignores the facts.[23]

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[22] The only proposed change to Rider PPO that is contested is the proposal to add Factor A4c, which would be initially set at zero, for energy imbalance costs. The PO has rejected this proposal. (See §VII.I of the PO) The other, uncontested changes to Rider PPO are described in §IV.D of IP's Initial Brief. In any event, none of the parties that participated in the entire case suggested the need for a transition mechanism such as MEA has proposed.

[23] Moreover, for virtually all customers, any changes in delivery services rates approved in this case will be offset by corresponding changes in the customer's transition charges ("TC").

The relatively minor change in overall customer impact also explains why MEA's reliance on a non-DST case is misplaced. The CIPS case cited by MEA (Docket 01-0446) involved CIPS' transition to a new Market Value Index ("MVI"). Thus, at issue was the actual price of energy (MEA's concern), not the prices for delivery services (which is at issue in the current case). In the context of Docket 01-0446, a significant change in MVI prices could affect many customers, by, for example, changing whether the customer has a positive TC. Indeed, in the CIPS case, both Staff and CIPS recognized that because the MVI pricing being placed into effect was significantly higher than the prior NFF pricing, many customers would no longer have positive TCs. (Order in Docket 01-0446, p. 5) Because of this significant customer impact, the Commission found that a transition plan was appropriate. (Compare the Order in Dockets 00-0259, 00-0395 & 00-0461 (Cons.), pp. 170-72 (IP's transition issues with respect to MVI implementation were addressed in the original MVI docket)) The situation in the CIPS docket cited by MEA and the situation in the present case bear no similarity.

Finally, the transition mechanism sought by MEA is in one respect unnecessary under IP's delivery services tariffs, and in another respect unlawful. MEA seeks language in the final Order that would authorize DST customers, within a specified time period, to (1) "terminate their delivery service contract with [IP] and return to bundled service," or (2) "terminate their Rider PPO contract with [IP] and obtain service from an Alternative Retail Electric Supplier." (MEA BOE, p. 4) However, IP does not require "delivery services contracts" with minimum term requirements. From IP's perspective, a customer taking delivery services from IP and energy supply service from a RES can terminate delivery services, and return to bundled service, within the time frames requested by MEA, through the normal application of the DASR process. Of course, the customer may have a power supply contract with the RES that has either a term requirement, or termination charges, or both. Presumably, MEA is not suggesting that the Commission should, or lawfully can, authorize customers to escape their RES contracts before their terms expire or without paying any termination charges specified in the contract. With respect to PPO customers, MEA's proposal is unlawful, because §16-110(b) of the PUA entitles the electric utility to require customers to purchase PPO service for a minimum one-year term, and IP has included the requirement of a one-year contract (so long as the customer's TC remains positive) in Rider PPO. (See IP Ex. 5.8, p. 1)

In sum, MEA's request should be rejected as unsupported by the record, unnecessary and, in some respects, unlawful.

CONCLUSION

For the reasons set forth in Illinois Power Company's Brief on Exceptions and in this Brief in Reply to Exceptions, the Commission should (1) revise the Administrative Law Judge's Proposed Order in accordance with Illinois Power's exceptions, and (2) reject the exceptions of the other parties, other than those exceptions that Illinois Power has expressly agreed to herein.

Respectfully submitted,

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