State of Illinois

Illinois Commerce Commission

COMMONWEALTH EDISON COMPANY	:	
	:	
Petition for approval of delivery services tariffs and tariff revisions and of residential delivery services implementation plan, and for approval of certain other amendments and additions to its rates, terms, and conditions	:	**No. 01-0423**

INITIAL BRIEF OF THE STAFF OF THE ILLINOIS COMMERCE COMMISSION

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NOW COMES the Staff of the Illinois Commerce Commission (“Staff”), through its attorneys, and files its Initial Brief in the above-captioned proceeding.

INTRODUCTION

On June 1, 2001 Commonwealth Edison Company (“ComEd”, “Edison” or “Company”) filed a petition for approval of delivery services tariffs and delivery services implementation plan, and for approval of certain other amendments and additions to its rates, terms and conditions. Various parties intervened including: Illinois Power Company, the People of the State of Illinois (“AG”), AES new Energy, Inc, Enron Energy Services, Inc., Blackhawk Energy Services, L.L.C., MidAmerican Energy Company, Cook County State’s Attorney’s Office (“Cook County”), the United States Department of Energy (“DOE”), Central Illinois Light Company (“CILCO”), the Citizens Utility Board (“CUB”), the City of Chicago (“City”), Peoples Energy Services Corporation, Illinois Industrial Energy Consumers (“IIEC”), Environmental Law and Policy Center, Midwest Generation, LLC, (“Midwest Generation”), National Energy Marketers Association (“NEMA”), Exelon Energy Company, TrizecHahn Office Properties, and Building Owners and Managers Association (“BOMA”).

The following witnesses testified for Staff: Garret E. Gorniak, Burma C.Jones, Bryan C. Sant, Carolyn Bowers, Janis Freetly, Mike Luth, Peter Lazare, Cheri L. Harden, Bruce A. Larson, Eric P. Schlaf, David A. Borden, and Alan Pregozen.

The following witnesses testified for ComEd: Arlene A. Juracek, Kenneth Gordon, Calvin Manshio, Jerome P. Hill, Philip E. Voltz, David G. DeCampli, Daniel E. Thone, Prof. Sam Peltzman, Christopher L. Culp, Ph.D., John E. Ebright, CPA, Alan Heintz, Jeff D. Makholm, Ph.D., Jennifer T. Sterling, P.E, Steven T. Naumann, P.E., Michael F.

Born, Pamela B. Strobel, David R. Helwig, P.E, Richard F. Meischeid II, Dr. James B. Williams, and the Panel Testimonies of Kathleen D. Leitzell and Michael J. Meehan, Sally T. Clair and Paul R. Crumrine, and Lawrence S. Alongi and Sharon M. Kelly, P.E..

Testifying for the various intervenors were the following: for AES new Energy, Inc, Enron Energy Services, Inc., and Blackhawk Energy Services, L.L.C., (collectively "ARES Coalition"), the panel testimony of Phillip R. O'Connor and Richard S. Spilky and Marc L. Ulrich, Ph.D.; for BOMA, Sheree L. Brown; for CILCO, Keith E. Goerss; for the City, Steven Walter; for the City, AG and Cook County, David A. Schlissel; for the City, AG, Cook County and CUB, David J. Effron and Edward C. Bodmer; for IIEC, Robert R. Stephens and Alan Chalfant; for Midwest Generation , John T. Long, Phillip W. Mcleod and Dr. George R. Schink; for NEMA, Craig G. Goodman; for TrizecHahn Office Properties, Larry Haynes and for DOE, Dr. Dale E. Swan.

Evidentiary hearings were held November 1, 2001 through November 16, 2001 and the record was marked heard and taken on November 16, 2001. Staff's Initial Brief follows.[1]

[1] On November 30, 2001, Staff filed its Response to Petition for Investigation and Response to Motion to Dismiss in Docket No. 01-0664. In that pleading and the attached Staff Report, Staff recommended that the Commission initiate an audit and investigation of ComEd actions related to its transmission and distribution systems covering the period from 1993 through 2000, inclusive. Staff also recommended that the schedule in this proceeding be adjusted so that the results of the audit and investigation could be used by the Commission to determine a just and reasonable revenue requirement on the basis of a calendar year 2000-test year in this proceeding. Staff notes that replies to the responses it and others filed on November 30, 2001, are due December 7, 2001. Without varying from its position that the Commission should conduct a Section 8-102 audit and investigation the results of which can be made of record in Docket No. 01-0423 for use by the Commission in setting just and reasonable rates in accordance with the Public Utilities Act and the Commission's Rules of Practice, Staff files this Initial Brief in order to articulate its position on the issues in this proceeding as they exist in the current procedural posture.

ARGUMENT

I. Legal Issues and Standards for Decision

A. Substantive Standards and Policies Governing Requested Rates

ComEd argues in this proceeding as it did in its last delivery service rate proceeding, ICC Docket No. 99-0117, that it is entitled to the "opportunity for full cost recovery" of its costs of providing regulated services. ComEd Ex. 3, p. 7. ComEd is wrong. Section 16-108 only provides that charges for delivery services are to be cost based, and the Commission shall allow the electric utility to recover the costs of providing delivery services through its charges to its delivery service customers that use the facilities and services associated with such costs. 220 ILCS 5/16-108(c). In addition, the Commission is required to establish charges, terms and conditions for delivery services that are just and reasonable and shall take into account customer impacts when establishing such charges. 220 ILCS 6/16-108(d). The plain language of the statute does not support ComEd's claims, that it is <u>entitled</u> to "full recovery" of its costs of providing delivery services". Section 16-108 does not mandate "full cost recovery" nor does Section 16-108 speak to "full" cost recovery. Section 16-108 does not, on its face, purport to change the basic nature of ratemaking. The charges established by the Commission are to be "just and reasonable" and are to take into account "customer impacts" 220 ILCS 5/16-108 (d). Nowhere does that section mandate a cost recovery methodology for delivery service implementation costs which guarantees "full" recovery. While, utilities are entitled to the opportunity to obtain recovery of their revenue requirements, if out-of-period expenses are not "determinable" with particular certainty, they may not be used to adjust test year expenses or be reflected in rates.

B. Procedural Issues (*e.g.*, Admissibility) Not Addressed in Specific Arguments

C. Other Policy Issues

1. Impact on Capital Markets and Cost of Capital

Dr. Peltzman and Dr. Culp testified on behalf of ComEd that the electric utility industry in Illinois is becoming more risky due to the reduction in regulation from the restructuring of electricity. They claim that restructuring creates risks from price arbitrage and classic externalities and will increase the impact of demand fluctuations on the variability of ComEd's cash flow. (ComEd Ex. 9.0 and 10.0) Dr. Peltzman testified that the risks from increased price volatility that ComEd will bear in the future will be priced into ComEd's equity today. (ComEd Ex. 9.0 at 9) Dr. Culp testified that as provider of last resort, ComEd's investors will require compensation for bearing additional risks in excess of that estimated via pure systematic risk-based cost of capital methods. (ComEd Ex. 10.0 at 11) Dr. Culp supported Mr. Thone's reliance on the Miller and Hamada models as well-accepted methods of assessing the effects of leverage on the cost of equity capital. (ComEd Ex. 30.0)

Ms. Freetly disagreed with Dr. Peltzman and Dr. Culp's assessment of the risk posed to ComEd due to the restructuring of electricity markets in Illinois. The restructuring of the industry has eliminated the risks associated with owning and operating generation that was previously borne by integrated electric utilities. In

October of 2000, Standard & Poor's (S&P) raised ComEd's corporate credit rating from BBB+ to A- and simultaneously raised ComEd's business position rating from 7 to 4. The ratings assigned by S&P reflect ComEd's solid financial measures and above average business profile which is supported by its low-risk electric transmission and distribution assets. (Staff Ex. 5.0 at 44-45) According to ComEd's S&P credit rating and business profile position, an upward adjustment to the cost of equity is unwarranted. (Staff Ex. 19.0 at 21) Mr. Pregozen further testified that due to S&P's independence and experience in analyzing the risk of utilities, the Commission should place much higher value on S&P's corporate credit and business position ratings than on the opinions of Dr. Peltzman and Dr. Culp. (Staff Ex. 26 at 20)

Mr. Walter also disagreed with Dr. Peltzman's perception of ComEd's risk level. He pointed out that the level of risk does not necessarily increase with the reduction of regulation. He testified that investment analysts tend to see Exelon stock as a good purchase with low risk and high potential. He also stated that the increased risks that ComEd faces are the result of ComEd's voluntary management decisions and ratepayers should not be penalized for the company's imprudence. He further pointed out that ComEd's testimony about the increased risk facing the company contradicts all the testimony the company filed in the recent Commission docket concerning the spin off of ComEd's nuclear generating stations, Docket Nos. 00-0369 and 00-0394. Throughout that proceeding, ComEd stated that the resulting lack of its own generation would have no effect on the riskiness of the Company's equity and would not affect the rate of return. (COC 1.0 at 5-14)

2. Impact on Customers

3. Impact on Cost Based Rates

4. Impact on the Development of an Effectively Competitive and Efficient Electricity Market

5. Impact on Distribution Adequacy and Reliability

6. Impact on Future Rate Cases

7. Other

II. Revenue Requirement Issues

A. Calculation of Revenue Requirement

Staff's proposed revenue requirement is $1,575,154,000. The revenue requirement schedules, including Staff's proposed rate base and cost of capital, are attached to this brief as Appendix A.

B. Selection of Test Year

Consistent with the position set forth in Staff's Response to Petition for Investigation and Response to motion to dismiss filed in ICC Docket No. 01-0664 on November 30, 2001, Staff's position is that the Commission should not set rates based on a calendar 2000 test year with <u>finality</u> until an independent expert has conducted an in depth investigation so that the Commission can be assured that the rates ultimately ordered into effect by the Commission are just and reasonable, in compliance with Articles IX and XVI of the Public Utilities Act ("PUA").

C. Rate Base

1. Functionalization of Distribution Plant

2. General and Intangible Plant -- Direct Assignment and Allocation

The evidence clearly supports the use of a labor allocator to functionalize General and Intangible Plant and Administrative and General (A&G) Accounts to distribution.

The record in this proceeding supports two conclusions concerning the functionalization of General and Intangible Plant and A&G accounts to distribution. First, a general labor allocator is more reasonable and more equitable than a direct assignment approach. The Commission approved a labor allocator in ComEd's last delivery service proceeding (Docket No. 99-0117) and the Company offers no credible evidence in this proceeding to deviate from that approach.

Second, the specific allocator to use for these accounts is Staff's proposed labor allocator. Staff's allocator appropriately takes into consideration the labor, not only for ComEd's existing production plants, but also for the fossil plants sold to Midwest Generation. The labor from the fossil plants should be included to properly account for their share of General and Intangible and A&G accounts.

ComEd proposes a flawed direct assignment methodology that has been previously rejected by the Commission for functionalizing these accounts.

ComEd proposes to functionalize General and Intangible and A&G accounts by a combination of detailed direct assignments with a variety of allocation factors. This approach is defended by ComEd witness Hill on two levels. First, he argues that the greater detail associated with the Company proposal ensures more accurate results. Mr. Hill states as follows:

> IIEC Witness Chalfant opines that he is concerned with the proper functionalization of costs attributable to delivery services. This is precisely one of the Company's principal objectives of this proceeding, "getting the delivery services price right". As described in my direct testimony, where sufficient data or information existed, the Company functionalized costs by direct assignment. Where information or data did not allow for direct assignment, the Company functionalized costs by utilizing the next best method, use of an allocator. (ComEd Ex. 23. 0, p. 5)

Second, Mr. Hill argues that the Company's proposal is consistent with past practice. Mr. Hill's consistency standard is not the approach that has been adopted by the Commission but rather the method proposed by ComEd in Docket No. 99-0117:

> Obviously, ComEd has <u>not</u> changed from its prior method of functionalizing these costs. As in Docket 99-0117, ComEd has directly assigned the General Plant and A&G costs where its accounting data is sufficient to do so. ComEd Ex. 23.0, p. 7.

> The inconsistencies far outweigh the consistency in ComEd's functionalization proposal.

ComEd's proposed functionalization methodology is riddled with inconsistencies at a variety of levels. First, the proposal is saddled with internal inconsistencies. Second, Mr. Hill's proposal is inconsistent with the Company's proposed methodology in Docket No. 99-0117. Third, the Company's proposal clearly conflicts with the methodology approved by the Commission in Docket No. 99-0117.

> The Company's proposed functionalization of General and Intangible Plant contains numerous internal inconsistencies.

The Company's proposed functionalization of General and Intangible Plant is contradictory and confused. The methodology Mr. Hill presents in his direct testimony conflicts with the approach he presents in rebuttal and, as a result, it is not clear what

ComEd is proposing in this case. For example, Mr. Hill contends in direct that transportation assets were functionalized to distribution based on a study performed in 1999 using 1997 data (Tr. 3215). However, he states in surrebuttal that the Company used an alternative approach based on an analysis in January 2001 that assumed full ownership of transportation equipment (Account 392) by the energy delivery function (Tr. 3213-4). Similarly, Mr. Hill maintains in direct that communication equipment (Account 398) was assigned based on the location of the equipment (ComEd Ex. 4.0, Appendix A, p. 6) while in surrebuttal he states that the direct assignment also considered the purpose of the equipment (Tr. 3219). Again, Mr. Hill states in direct that Miscellaneous Equipment (Account 398) was functionalized according to the number of employees (ComEd Ex. 4.0, Appendix A, p. 7). However, Mr. Hill contends in surrebuttal that it was based on the location of the equipment (Tr. 3220).

These discrepancies undermine the Company's proposed functionalization on two counts. First, they impede a review of the Company proposal at the most basic level. If the Company itself is confused about its proposed functionalization of General Plant, then others will find it difficult to understand ComEd's proposal and verify its accuracy.

Second, this confusion on Mr. Hill's part does not instill confidence in ComEd's functionalization proposal. If the Company cannot even explain its proposal, that makes it difficult to believe that ComEd can actually functionalize General Plant in a fair and reasonable manner.

ComEd's proposed functionalization also conflicts with its proposed approach in Docket No. 99-0117.

Mr. Hill defends ComEd's proposed functionalization as consistent with its proposed approach in its previous case (Docket No. 99-0117). According to Mr. Hill, "ComEd has not changed from its prior method of functionalizing these costs" (ComEd Ex. 23.0, p. 7). However, Mr. Hill's claim is undermined by a number of discrepancies between the two proposals.

One discrepancy pertains to the treatment of Intangible Plant between the two cases. For the current test year, Mr. Hill acknowledged a total of $166 million in Intangible Plant Account 303 related to capitalized computer software for ComEd and Exelon Business Services Company (Tr. 3190-1). This represents a considerable increase from the zero balance for Account 303 in Docket 99-0117 (Tr. 3201). Because of this zero balance in the applicable account, Mr. Hill was asked how the Company (1) accounted for and (2) functionalized capitalized software in Docket No. 99-0117. However, he did not know the answer to either question (Tr. 3202). If Mr. Hill does not know how the Company accounted for or functionalized capitalized computer software in Docket No. 99-0117, he cannot claim the Company's approach is consistent with Docket No. 99-0117.

For General Plant accounts, Staff presented an analysis quantifying the inconsistencies between ComEd's approach in this case and Docket No. 99-0117 (Staff Ex 21, Schedule 21.1). Staff compared ComEd's proposed allocations of General Plant and A&G accounts to distribution between this case and Docket No. 99-0117 and found significant variations between the two. For General Plant, ComEd's proposed allocation of Account 389, Land and Land Rights declined by 37% from

$11,255,971 in Docket No. 99-0117 to $7,097,472 in the current proceeding while the proposed allocation of Account 391, Office Furniture and Equipment, increased by 72% from $60,821,929 in Docket No. 99-0117 to $104,962,371 in the current case. The proposed allocation for Account 396, Power Operated Equipment, fell 52% from $4,629,732 to $2,230,719 while the allocation of Account 398, Miscellaneous Equipment, has increased by 304% from $349,968 to $1,414,665 from Docket No. 99-0117 to this proceeding. These fluctuations indicate that the Company's direct assignment method of functionalization in this docket is as unreliable as the Company's direct assignment method of functionalization proposed and rejected in Docket No. 99-0117.

ComEd's proposed functionalization clearly conflicts with Commission precedent.

The most important consistency issue concerns the consistency of the Company's proposal with the Commission Order in Docket No. 99-0117. This issue is key because the Commission, not the Company, determines the appropriate allocation of these accounts. In its Order, the Commission expressly rejected ComEd's proposal to functionalize on the basis of detailed direct assignments in favor of a general labor allocator. The Commission concluded as follows with respect to General Plant accounts:

> The Commission disagrees with Edison's direct assignment approach. The very nature of these costs suggests that they are not amenable to direct assignment. In previous cases, Edison used a labor allocator to assign these costs. Edison has not made a convincing argument for deviating from this past practice. Order, p. 11.

The Commission drew a parallel conclusion for A&G accounts:

> While direct assignment may be a better method in some cases, the Commission does not believe costs, which include CEO and executive salaries, are amenable to direct assignment. Were such costs amenable to direct assignment, Edison would have assigned these costs directly to the distribution function in prior cases. Edison did not. For the same reasons that we disagreed with Edison's direct assignment of General Plant costs, we also disagree with Edison's direct assignment of A&G expenses. We, therefore, adopt IIEC's proposal for allocation. Order, p. 27.

This decision is striking because of the breadth of the Commission's conclusion on these issues. The Commission objected, not just to ComEd's specific proposal in the case, but to the general concept of functionalizing these accounts on the basis of direct assignments. The Company proposal clearly indicates that ComEd has failed to heed the Commission on this issue. ComEd proposes to use the same direct assignment approach in this case that the Commission rejected in no uncertain terms in Docket No. 99-0117.

ComEd's efforts to justify this divergence from Commission precedent lack foundation.

Company witness Hill seeks to explain ComEd's failure to heed the Commission's conclusions for General and Intangible plant. He claims that changes in the Company's business structure undermine the relevance of the Commission's Order in Docket No. 99-0117 for the current proceeding. Mr. Hill contends that during the test year ComEd began to replace the Company's vertically integrated structure with a structure divided into generation, transmission and distribution components. According to Mr. Hill, this realignment makes the functionalization process more conducive to direct assignment then general allocation:

> This comparison to prior Commission Orders misses the point that the Company was vertically integrated at the time of its prior delivery services rate proceeding, Docket No. 99-0117, but is restructured and realigned at the time of this proceeding. (ComEd Ex. 23.0, p. 6)

Mr. Hill's argument is unpersuasive. ComEd's decision to reorganize provides no justification to abandon the Commission's decision on this matter. Mr. Hill's restructuring argument does not address the general concern by the Commission about the use of direct assignments for these accounts. The Commission did not suggest that it opposes direct assignments only for a utility structured along vertical lines. Therefore, ComEd's restructuring has no bearing on the Commission's conclusion for these accounts.

Furthermore, by arguing that restructuring justifies the use of direct assignments over the Commission-approved labor allocator, Mr. Hill uses this reorganization as a tool to shift costs from generation to distribution and thereby penalize delivery services ratepayers in the process. ComEd certainly may realign its business structure for its own purposes but it should not be done at ratepayers' expense.

Mr. Hill inappropriately bases his functionalization for the 2000 test year costs on a business restructuring undertaken in 2001.

There is a fundamental problem with Mr. Hill's arguments concerning the restructuring process ComEd claims to have undertaken during the test year. The problem is that the Company did not even begin to restructure until after the test year ended in January 2001 (ComEd Ex. 4.0, Appendix A, p. 1; Tr. 3210-3211).

This discrepancy undermines the foundation for ComEd's proposed functionalization in this case. It calls into question the statement by Mr. Hill that:

> the Company has made it clear that the formation of separate business functions that occurred beginning in 2000 has allowed the functionalization of a large portion of these costs using direct assignment (ComEd Ex. 23.0, p. 7).

This discrepancy undermines Mr. Hill's argument in other ways. Mr. Hill indicates that the functionalization of General Plant Accounts 390 (Structures and Improvements); 391 (Office Furniture and Equipment; 397 Communications Equipment) and Intangible Plant Account 303 all involve an intermediate allocation to Exelon Business Services Company (BSC) (ComEd Ex. 4.0, Appendix A). However, BSC was not formed until 2001, which means it could not have played a role in the functionalization of these costs for the test year.

This January 2001 timeline for ComEd's restructuring also plays havoc with Mr. Hill's proposed functionalization of Intangible Plant. The methodology is described by Mr. Hill in surrebuttal as follows:

> The assets in Intangible Plant accounts generally reflect the Company's capitalized investment in large software systems. Similar to all the assets on prior ComEd vertically-integrated balance sheets, these assets have been analyzed and assigned (outside the context of a rate case), again with review by the Company's independent auditors, to the restructured legal business entities. So, unlike in the prior delivery services rate case (Docket No. 99-0117), no allocation is required except to remove the transmission portion from ComEd (See WPB-1.1, page 7 of the workpapers) and to allocate applicable portions of the Exelon Business Services Company, including the Corporate Center, intangible plant to jurisdictional energy delivery service (See WPB-1.1, page 9). ComEd Ex. 45.0, pp. 11-12).

As with General Plant, Mr. Hill bases his proposed functionalization for Intangible Plant on the faulty premise that the Company restructured during the test year. However, the Company retained its vertical structure throughout the test year, which makes his proposed assignment of test year assets to restructured legal business entities clearly inappropriate. Furthermore, Mr. Hill's direct assignment assumes that Intangible Plant assets related to the CBMS accounting system are majority owned by Exelon Business Services Company (ComEd Ex. 45.0, p. 12). However, Mr. Hill conceded under cross that ComEd, rather than Exelon Business Services, was the majority owner of CBMS for the test year (Tr.3213). These discrepancies call into question the accuracy and value of the Company's proposed functionalization of Intangible Plant.

This confusion about the timeline for ComEd's restructuring raises an obvious credibility issue for Mr. Hill. If he cannot get this basic matter straight then how can Mr. Hill be expected to present more detailed and complex information concerning the functionalization of common costs in a fair and accurate manner?

Approval of the Company's proposed functionalization methodology would produce a double standard for Illinois utilities.

In contrast to ComEd, other Illinois utilities such as AmerenUE and AmerenCIPS have adhered to the Commission-approved labor allocator for functionalizing General and Intangible Plant in this round of delivery services cases. If the Commission accepted ComEd's proposal in this case, it would be applying a double standard in favor of those utilities that disregard Commission opinions over utilities that adhere to those opinions. That would be a dangerous precedent indeed.

Staff's proposed functionalization methodology for General and Intangible Plant and A&G accounts should be adopted in this proceeding.

Staff has proposed an adjustment in this proceeding based upon applying the labor allocator adopted by the Commission in Docket No. 99-0117 to the functionalization of General and Intangible Plant in this proceeding. Staff is joined by IIEC and the City in proposing adjustments to the functionalization of General and Intangible Plant and A&G expenses based on the Commission-approved labor allocator. However, their proposed adjustments fall short in key respects. IIEC's adjustment covers General Plant and A&G accounts but does not include Intangible Plant. Furthermore, the adjustments by both IIEC and the City do not take into consideration the fossil plants sold by ComEd prior to the test year.

Intangible Plant should be included in the adjustment to make ComEd's allocation methodology consistent with Commission decisions in other proceedings on this issue. Intangible Plant was not an issue in Docket No. 99-0117 because the Company had identified only $80,375 of Intangible Plant to functionalize. The increase of the Intangible Plant balance to $179,899,429 in the test year makes this a relevant issue for the current proceeding. In the initial delivery services dockets for other utilities the Commission approved a labor allocator for Intangible Plant as well. In addition, Ameren in its current delivery service case (Docket No. 00-0802) proposed a labor allocator for Intangible Plant which has been accepted by the ALJ. Applying the labor allocator to Intangible Plant in this case would align ComEd with these decisions.

The labor allocator for these accounts should include labor from the fossil plants sold by ComEd to Mission Energy in 1999.

The record demonstrates that the labor allocator for this case should include the labor associated with the fossil plants that ComEd divested before the test year. The reason stems from the Commission Order in Docket No. 99-0117 which adopted a labor allocator that included labor from ComEd's fossil plants. When ComEd sold those plants to Mission Energy in November 1999, it failed to adjust downwards the General and Intangible Plant accounts associated with these plants based on the Commission-approved methodology. This has increased the allocation of General and Intangible Plant to the remaining regulated company and laid the groundwork for higher delivery services rates.

This increase is particularly inappropriate considering that the decision to sell those plants was the Company's alone and the $4.813 billion received from that sale went to the Company, not ratepayers. Given ComEd's tangible benefits from the sale, ratepayers should not be penalized by a reallocation of General and Intangible Plant and A&G account balances to delivery services.

The Company's failure to appropriately allocate General and Intangible Plant also conflicts with its assurances regarding the sale of these units. In advocating the plant sale, ComEd stressed the benefits not only to the Company, but also to ratepayers and the market as a whole:

> In sum, consummation of the fossil plant sale will provide numerous benefits for ComEd, its customers and other parties with an interest in a more competitive generation market. ComEd Notice of Property Sale, May 12, 1999, p. 6.

The Company's treatment of General Plant and A&G accounts undermines this statement. By increasing the allocation of these accounts to non-fossil utility functions, ComEd lays the groundwork for higher delivery services rates. These higher rates would make delivery services a less attractive alternative to bundled rates and hinder, rather than advance, competition.

The specific adjustment proposed by Staff is reasonable and should be adopted.

The specific adjustment proposed by Staff reallocates General and Intangible Plant as well as A&G accounts based on a labor allocator that includes labor from the divested fossil plants. This produces adjustments of: $(405,160,914) in Gross Plant; $1,035,274 in Depreciation Reserve; $555,976 in ADIT and Other Rate Base Items; and $(60,002,014) in expenses. The proposed adjustment reflects the difference in the revenue requirement that results from using a labor allocator to functionalize General and Intangible Plant and A&G expenses in the Company's cost of service study.

The starting point for Staff's proposed labor allocator is the labor allocator contained in the Company's cost of service study. The allocator has been revised by substituting the production labor amount from the Company's 1999 FERC Form 1 (p. 354, line 18) for the production labor amount in the Company's cost of service study. This increases the production component of the allocator from $448,246,408 to

$538,203,725 and decreases the distribution share of labor from 36.94% to 33.06%. The 1999 figure was used because it represents the most recent year that ComEd included labor costs from the fossil plants. This is the most reasonable figure to use to reflect the role of the fossil plants in the labor allocator. The transmission and distribution components of the Company's allocator were not revised in order to remain as consistent as possible with the other components of the Company's test year labor costs. The development of the proposed adjustment is presented in Staff Ex. 21.0, Schedule 21.2.

3. Known & Measurable Changes to Test Year Plant Balances

4. Other Adjustments to Rate Base

a. Budget Payment Plan

Staff witness Jones proposed an adjustment to reflect a 13-month average of Budget Payment Plan balances in the Company's test year rate base. (Staff Ex. 2.0, pp. 3-4 and Schedule 2.1) The Company argues that Budget Payment Plan balances are an element of cash working capital and should not be considered separately. The Company chose not to request working capital in this current proceeding. Curiously, the Company did not object to a similar adjustment in Docket No. 99-0117 that added approximately $10 million to rate base.

It is appropriate to consider Budget Payment Plan balances as an independent component of rate base, whether or not working capital is also included; the Commission has often done so. Ms. Jones cited several cases, including several of the prior DST cases. (Staff Ex. 16.0, pp. 2-3)

In this case the average of Budget Payment Plan balances represents an overpayment by ratepayers. Therefore, ratepayer supplied funds are available for the Company's use and should be deducted from the rate base on which the Company is expected to earn a return. Ms. Jones' adjustment to include the13-month average of Budget Payment Plan balances in the Company's test year rate base is reasonable and proper and, therefore, should be accepted.

5. Plant Adjustments

a. Plant Expenditures for Q2 2001

The Company proposes to include in rate base plant additions through June 30, 2001. Staff proposed an adjustment to limit the amount so included in rate base to the actual amount incurred for these plant additions rather than the amount ComEd had previously estimated for these plant additions.

The Company proposed that $126.592 million would be spent on projects reasonably expected to be placed in-service in the second quarter of 2001 (ComEd Schedule B-2.2, p. 2 of 2 line 5) and included a related $3.224 million of accumulated depreciation and $.603 million of deferred income taxes for a net addition to rate base of $122.765 million.

Staff Data Request GEG-1.01 requested a listing of amounts reflected in this category that have been actually placed in-service in the second quarter of 2001. The Company in its corrected response to the request stated that all projects were in service as of the end of the second quarter of 2001 and that $115.554 million had been expended on those projects. Mr. Gorniak made an $11.038 million adjustment to reflect the decrease in amount spent on these projects. (ICC Staff Ex. 15.0 CR2, Schedule 15.1, p. 1 of 2) He made a related adjustment of $.277 million decreasing accumulated depreciation and a $.052 million adjustment decreasing accumulated deferred income taxes for a net reduction to plant and rate base of $10.709 million. The related deprecation expense adjustment was a reduction of $.277 million.

ComEd Witness Voltz presented Surrebuttal Testimony indicating that despite the projects being put in service as of June 30, 2001, an additional $8.1 million or a total of $123.680 million has been spent on these projects as of September 30, 2001. (ComEd Ex. 46.0, p. 2) He even speculated that project expenditures were to continue on some projects in the months to come that may make the original forecast of expenditures of $126.592 million realistic. Although Staff was eager to review and consider the evidence supporting the recent expenditure, there was nothing other than a statement saying the money was "spent" in Mr. Voltz's testimony. Nowhere did he testify why expenditures were made on these projects after they were placed in service. Also, he did not testify as to what these further additions were after the plant was in service, why they were necessary nor did he provide any basis upon which Staff could determine if they were reasonable. There was no evidence such as invoices, work orders or even bookkeeping entries to indicate that the expenditures were even made.

Therefore, Staff rejects Mr. Voltz's sudden claim in his Surrebuttal Testimony that additional expenditures were made post June 30, 2001 for plant that was in service as of June 30, 2001. Mr. Voltz also failed to provide any associated changes to deferred taxes, accumulated depreciation, or depreciation expense that are in line with the claim of $123.680 million of expenditures.

Mr. Gorniak's adjustment allowing $115.554 million for plant put into service in the 2nd quarter of 2001 along with the associated adjustments for accumulated deprecation, accumulated deferred income taxes and depreciation expense is reasonable and supported by the record.

b. Proposed Retired Plant

Staff witness Gorniak proposed an adjustment to remove from rate base plant which the Company identified as no longer used and useful, but for which the Company had not yet recorded a plant retirement. (ICC Staff Ex 1.0, pp. 3-4, and Schedule 1.1) Although the Company has slated certain plant for retirement, Mr. Gorniak testified that through his Data Request GEG-7.04, he inquired whether all plant that was considered retired, replaced, or no longer used and useful for the year 2000 was removed from the filing. The Company responded that $32.156 million of plant of that type had not been removed from the filing. Mr. Gorniak removed this amount from plant in service contained in the filing, along with removing $32.156 million from accumulated depreciation plus he proposed an adjustment to decrease associated depreciation expense by $.858 million. The Company did not oppose this adjustment. (ComEd Ex. 23.0, p. 3) Mr. Gorniak's adjustment is reasonable and proper and should be accepted.

c. Retirements Related to 2001 Replacement Plant

Staff witness Gorniak proposed an adjustment to reflect the retirements of old plant that would be replaced by new plant that would be put in service in 2001. (ICC Staff Ex. 1.0, pp. 4-5, and Schedule 1.2) The Company did not oppose this adjustment. (ComEd Ex. 23.0, p. 3)

The Company has proposed in its filing that certain plant put in service in 2001 be included in rate base. (ComEd Schedule B-2.2, pp. 1-2) Mr. Gorniak testified that through his Data Request 7.03, he inquired whether some of this plant was replacement plant and if it were, whether any retirements were considered in the filing. He testified that if retirements had not been taken into consideration, there would be a double counting of this plant. First, there would be plant included in the filing as of December 31, 2000 that was subsequently replaced, and second there would be the plant put into service in 2001 that replaced that plant. He further testified that any such plant and related accumulated depreciation and depreciation expense whose replacement was included by the Company in its rate base, should be excluded to avoid the double counting. The Company's response to his request labeled Combined Supplemental response to GEG-7.03 and GEG-7.04 indicated there was, in fact, such type of plant. Mr. Gorniak proposed an adjustment to eliminate the double counting.

Mr. Gorniak proposed to remove $11.060 million from plant in service contained in the filing, along with removing $11.060 million from accumulated depreciation and he further proposed an adjustment to decrease associated depreciation expense by $.279 million. The Company did not oppose this adjustment. (ComEd Ex. 23.0, p. 3) Mr. Gorniak's adjustment is reasonable and proper and should be accepted.

d. Accumulated Depreciation Adjustment Related to Overtime and Alleged Premiums Paid

Mr. Gorniak made an adjustment to decrease accumulated depreciation and depreciation expense for the plant adjustment related to premiums paid to contractors that was discussed by Staff Witness Bruce Larson at ICC Staff Ex. 23.0. Mr. Gorniak's proposed adjustment decreases accumulated depreciation by $.904 million and decreases depreciation expense by $.603 million. (ICC Staff Ex. 15.0 CR2, Schedule 15.2, p. 1 of 2) The adjustment was computed based upon a 3.6% depreciation rate for non-high voltage distribution plant. ComEd Witness Jerry Hill disputed the depreciation rate used citing unspecified "Company data" that indicates part of the additions were high voltage plant which is depreciated at 2.4%, in which case some composite depreciation rate could possibly be used. (ComEd Ex. 45.0, l. 757-761) Staff asked for clarification as to what overall composite depreciation rate the Company believed would be appropriate. (Staff Data Request BAL-5.04) Despite Mr. Hill's criticism of Staff's depreciation rate, no version of what the Company considered a proper composite rate was provided in the response to Staff's data request. (Staff Cross Ex. 70) In fact, Mr. Hill, could not point to what would be a proper depreciation rate in the data response. Nor did he suggest any particular rate, stating only that it could somehow be computed from the response, despite the lack of any numbers contained in that Company Data Response. (Tr. 3186)

Mr. Gorniak made a similar adjustment to decrease accumulated depreciation and depreciation expense for the plant adjustment related to ComEd overtime that was also discussed by Staff Witness Bruce Larson at ICC Staff Ex. 23.0. Mr. Gorniak's proposed adjustment decreases accumulated depreciation by $.317 million and decreases depreciation expense by $.240 million. (ICC Staff Ex. 15.0 CR2, Schedule 15.3, p. 1 of 2) It too, was computed based upon a 3.6% depreciation rate for non-high voltage distribution plant. ComEd Witness Jerry Hill again disputed the depreciation rate used citing unspecified "Company data" that indicates part of the additions were high voltage plant, in which case some composite depreciation rate could possibly be used. (ComEd Ex. 45.0, lines 757-761) He provided no such alternative composite depreciation rate as discussed above.

Staff's depreciation rate is proper and is based upon the best information available to Staff. Despite the Company's disagreement and insistence that some composite depreciation rate be used, the Company, despite being asked by Staff through data request and cross examination, has provided no such rate for Staff to consider. Staff's adjustment is made on a proper basis given the evidence and the information ComEd chose to make available.

e. Deferred Taxes Related to Overtime and Alleged Premiums Paid

Mr. Gorniak made an adjustment to decrease accumulated deferred income tax expense for the plant adjustment related to premiums paid to contractors that was discussed by Staff Witness Bruce Larson at ICC Staff Ex. 23.0. Mr. Gorniak's proposed adjustment decreases accumulated deferred income taxes by $.369 million. (ICC Staff Ex. 15.0 CR2, Schedule 15.2, p. 2 of 2) It was computed based upon a 3.6% depreciation rate for book purposes for non-high voltage distribution plant. ComEd Witness Jerry Hill disputed the depreciation rate used citing unspecified "Company data" that indicates part of the additions were high voltage plant, in which case some composite depreciation rate could possibly be used. (ComEd Ex. 45.0, l. 757-761) He provided no such alternative composite depreciation rate as discussed above.

Mr. Gorniak made a similar adjustment to decrease accumulated deferred income taxes for the plant adjustment related to ComEd overtime that was also discussed by Staff Witness Bruce Larson at ICC Staff Ex. 23.0. Mr. Gorniak's proposed adjustment decreases accumulated deferred taxes by $.094 million. (ICC Staff Ex. 15.0 CR2, Schedule 15.3, p. 2 of 2) It too, was computed using a book depreciation rate of 3.6% for non-high voltage distribution plant. ComEd Witness Jerry Hill again disputed the depreciation rate used citing unspecified "Company data" that indicates part of the additions were high voltage plant, in which case some composite depreciation rate could possibly be used. (ComEd Ex. 45.0, l. 757-761) He provided no such alternative composite depreciation rate as discussed above.

Staff's book depreciation rate used in the computation of deferred taxes is proper and is based upon the best information available to Staff. Despite the Company's disagreement and insistence that some composite depreciation rate be used, the Company, despite being asked by Staff through data request and cross examination, has provided no such rate for Staff to consider. Staff's computation of the adjustment is made on a proper basis given the evidence and the information ComEd chose to make available.

6. Prudence of Distribution Capital Investment Costs

a. Affect of Alleged Imprudence on Rates

b. Prudence of Specific Distribution Capital Investments in Rate Base

In July and August of 1999, ComEd experienced widespread, high profile outages of its distribution system. As a result of these outages, ComEd began an unprecedented construction and maintenance program to upgrade its facilities. Both internal and external audits revealed that many parts of ComEd's distribution infrastructure were woefully inadequate. ComEd set goals to install as much capacity as possible before the summer of 2000, and again for the summer of 2001. In many instances, ComEd paid premiums for early completion of projects, either in the form of higher payments to contractors or overtime pay to ComEd employees. Staff Ex. 9.0, pp.1-2.

To explore the possibility of imprudent costs, Staff primarily relied upon the "Transmission and Distribution Investigation Report" by ComEd, dated September 15, 1999 and the "First Report of the Investigation of Commonwealth Edison's Transmission and Distribution Systems", by Liberty Consulting dated June 2000.

The Liberty Report found that ComEd's primary criterion for distribution expenditures in the 1990s was to minimize cost. ComEd allowed equipment loadings to become very high, which meant that, among other things, in case of a failure of one piece of equipment, ComEd could not switch the load to other equipment without overloading the alternative equipment. In addition, ComEd allowed a large backlog of maintenance, which increased the probability of an outage, with each outage representing the collapse of the house of cards that ComEd's system had become. Staff Ex. 9.0, pp.2-3.

It is easy to understand that, as the loading of transformers increases, more and more equally highly loaded transformers are required as backup. A transformer loaded at 50% needs only one other transformer, also loaded at 50%, as backup. A transformer loaded at 80% needs four other transformers, also loaded at 80%, as backup. ComEd routinely expected numerous transformers to carry loads in excess of

100%. Obviously, if one of these transformers failed, service interruptions were likely.

Staff Ex. 9.0, p. 3.

ComEd's own report, "Transmission and Distribution Investigation Report", released September 15, 1999, also known as *A Blueprint for Change*, states:

> The major findings reveal serious issues in the transmission and distribution system, especially in the areas of system maintenance, planning and design. (Emphasis in original)
>
> …
>
> ComEd must:
>
> - **Find the problems in the design and maintenance of the entire system;**
> - **Face the problems with clear management accountability; and**
> - **Fix the problems so customers across the system receive service which meets and exceeds industry norms.** (Emphasis in original)

Staff Ex. 9.0, p. 3.

The report made five recommendations. The recommendations are as follows, starting at page A.11.

> **(1) Maintenance:** As the tortured summer saga of Line 5348 suggests, the investigation found that a utility like ComEd needs to be painstaking in the care and feeding of its T&D components. The team found that other major cities operate T&D equipment that is no newer, no older – not fundamentally different from ComEd's. The task force findings pinpoint the crucial difference between ComEd's equipment – which failed this summer – and similar systems elsewhere that did not: ComEd has been unable to provide the rigorous care and maintenance that the T&D system requires for optimal reliability.
>
> It was generally found that while ComEd's inspection programs seemed appropriate, there were only imperfect mechanisms in place to ensure execution. It looked good on paper, but the repeated outages made the truth of the matter painfully clear. It is not certain, from a review of the records, how often inspections were actually performed, and the inspections that were performed may have been too passive, too cursory, to truly maintain the system.
>
> Additionally, the Report concludes that ComEd needs to ensure better follow-up on maintenance requests. While virtually all T&D emergencies are dealt with immediately, there appear to be altogether too many deficiencies

which, had they been identified and addressed sooner, would not have become critical in the first place. Too often, the priority of requests for maintenance was not recognized, and the request was simply added to a list. The Report also indicates that routine maintenance requests on the list were rarely tracked to ensure follow-up, and that the list was rarely updated to indicate which requests had already been addressed.

Specifically, the Investigation Report presents the following findings about ComEd's maintenance program:

<u>Management Systems.</u> ComEd's maintenance program is hampered by incomplete definition, lack of focus, historic budget swings, suboptimal work planning and inconsistent supervision.

<u>Equipment Monitoring and Capacity Management.</u> Too much of ComEd's maintenance work is reactive rather than preventive, driven by actual or pending equipment failures, because of insufficient monitoring and inadequate capacity (monitoring and capacity are discussed separately below).

<u>Program Execution.</u> ComEd's maintenance program has been hindered because of gaps in equipment condition monitoring, inconsistent training and work practices, and unclear priorities.

<u>Recordkeeping and Documentation.</u> ComEd maintenance efforts are often made more difficult by incomplete operating histories of components due to gaps in data capture, inattention to detail, and lack of workforce discipline. Staff Ex. 9.0, pp.3-5.

ComEd's report continues, at page A.12.

(2) <u>Equipment Protection and Monitoring</u>: As mentioned above, ComEd's physical equipment is largely comparable to that of other utilities in major metropolitan areas. In addition to improving its maintenance practices, however, ComEd needs to strengthen its equipment monitoring and protection. By improving its <u>monitoring</u> practices, ComEd will be better able to predict <u>when</u> certain types and pieces of equipment are likely to wear out or fail. Predicting (and thus preventing) the on-line failure of a component helps protect the equipment around it: when one component fails, the power originally carried by that component must travel through alternative routes using the surrounding components. This is what happened on July 30, when the sudden overload caused by the failure of Line 5348 acted to shut down the adjacent transformers.

Specifically, the Investigation Report presents the following findings about ComEd's equipment protection and monitoring:

> Maintenance Program Ownership. It was not always clear who was responsible for specific elements of ComEd's protection and monitoring program. Even when the responsible party was clearly identified, he or she was not always held accountable, in a meaningful way, for the performance of those elements.
>
> Calibration Maintenance. ComEd has not kept pace with the necessary relay calibrations, and its efforts to do so are hampered by the same types of issues described above with respect to other types of systems maintenance.
>
> Root Cause Analysis. ComEd has not effectively tracked and analyzed information about relay failures, and thus cannot analyze or address the root causes of those failures.
>
> Equipment Condition Monitoring. ComEd has not implemented a consistent program of equipment monitoring across its system, thus limiting its ability to detect incipient failures. Staff Ex. 9.0, p. 5.

The ComEd report continued at page A.13.

> **(3) T&D Load and Capacity:** It is obvious from the system failures this summer that the ComEd power delivery system is overloaded at some points. ComEd was aware that certain substations were overloaded at times of peak summer demand and was working to address the situation as outlined in its agreement with the City of Chicago. But the recent investigation revealed that the extent of the problem had been underestimated. ComEd's experts calculate that the T&D system is five to ten percent deficient in its capacity to carry the peak load, which must be contemplated in the wake of this summer's experiences. The problem is not a lack of power. Between construction, importation and its fleet of nuclear plants, ComEd expects to have a sufficient supply of power. The problem is that the distribution system cannot reliably deliver the power to its customers at peak times. ComEd needs to redesign some parts of its system to make better use of the physical components that are already in place, and invest in greater capacity to help it carry the load.

Specifically, the Investigation Report presents the following findings about the load and capacity of ComEd's T&D system:

- Substation Capacity. Upon initial review, it appears that almost a third of ComEd's large substations (approximately 73) operate above capacity at time of peak demand, and that 27 of those substations require expedited corrective actions. Three of those 27 substations are located in the City of Chicago (Crosby at 1180 North Crosby, Lakeview at 1141 West Diversey, and Northwest at 3501 North California), and 24 are located outside the City.

- Distribution Feeder Capacity. Upon initial review, it appears that almost one fifth of ComEd's small substations and feeders (approximately 880) operate above capacity at times of peak demand; 185 of those small substations and feeders are located in the City.

Staff Ex. 9.0, p.6.

The ComEd report continues at page A.14.

(4) T&D System Optimization: The distribution system serving downtown Chicago has evolved over the years to a condition that is particularly sensitive to inaccuracies in planning and the impacts of maintenance outages and equipment failures. Its apparent radial design is really an arrangement of radial arms of electrical loops similar to that employed in many highly reliable European designs, except with less capacity and configuration redundancy. It is the uniformly high loads carried on the system and the limited load transfer capability which combine to make this an unforgiving situation. Additionally, the ComEd system was found to contain some unique and limiting features which compound the impact of equipment outages and failures.

Achievement of improved service reliability will require the careful balancing of capacity additions and configuration enhancements.

Specifically, the Investigation Report presents the following findings about the load and capacity of ComEd's system design:

- System Design. ComEd's downtown distribution system lacks some of the features which provide high reliability and flexibility in other US and European designs.

- Delivery Capacity. Additional power delivery capacity is needed to provide the operating flexibility and contingency management capability needed to ensure highly reliable service.

- System Operation. Traditional contingency planning criteria applied to this system will not provide the requisite reliability for such an important area.

Staff Ex. 9.0, pp.6-7.

And finally, the ComEd report continues at page A.15.

> **(5)** **<u>Organization and Management</u>:** As the results of the investigation have unfolded, a wide variety of underlying organization and management issues have surfaced. A series of realignment workshops used to establish the transition organization for T&D (as described below) identified further evidence of the same issues, confirming the findings of the investigation with respect to organization and management issues. The issues identified in the Report fall into five categories, all related to just "doing the work": leadership, organization design, work processes, information systems and staff.

Staff Ex. 9.0, p. 7.

It is apparent from ComEd's report and from the Liberty report that ComEd failed to adequately plan and maintain their distribution system. When ComEd's negligence finally caught up with the utility and overloaded and ignored equipment began to fail, ComEd's distribution system required extraordinary upgrading, reconditioning and repair in the short time available before another summer subjected it to more stress. This involved contracting with many different firms and paying premiums for much of that work, and having ComEd workers put in many thousands of hours of overtime. If ComEd had been adequately maintaining and upgrading their distribution system all along, the work ComEd crammed in a few short months could have been done in a controlled manner, over a longer period of time, and at a lower cost. Staff Ex. 9.0, pp.7-8.

The premiums ComEd paid to contractors and additional overtime pay to ComEd employees are not prudent expenditures. Finishing the work quickly was important and probably prudent, given ComEd's self-imposed situation, but ComEd should have avoided the premiums and overtime with prudent planning and upgrading of its distribution system. In other words, ComEd was not prudent to neglect its distribution system, causing it to degrade and become unreliable, and requiring premiums and overtime expense during the resulting emergency recovery period. Staff Ex. 9.0, p. 8.

ComEd's situation on this issue is comparable to that of CILCO's Springfield natural gas distribution system back in the early 1990's. (see Docket No. 94-0040.) CILCO had deferred maintenance and repair of its cast iron mains in the City of Springfield to the point where it was no longer able to safely perform its function to deliver gas. CILCO management that was directly responsible for the cast iron mains knew of the deteriorated state of the mains, but did nothing. When CILCO upper management was made aware of the magnitude of the problem, CILCO, like ComEd, mounted a massive reconstruction effort. Outside contractors were brought in and CILCO workers performed many hours of overtime. The cast iron mains were replaced in an expedited fashion on a compressed schedule. Staff Ex. 9.0, p. 8.

That issue was addressed in Docket No. 94-0040. The Order states:

> The Commission rejects CILCO's arguments to the contrary and finds that allowing the Springfield system to deteriorate to the point of creating a public safety hazard necessitated an accelerated renewal program which led to a level of expenditures that would not normally be required had CILCO been conducting business in a reasonable prudent manner.
>
> The Commission is of the opinion that such a course of conduct requires the disallowance of some of the expenses associated with the Springfield renewal program. (Order at 15.)

Staff Ex. 9.0, p. 9. ComEd allowed its distribution system to deteriorate to the point of creating a public safety hazard. Inoperative traffic signals, elevators, air-conditioners, and slowed public transportation are a public safety hazard.

Staff proposes to adjust for ComEd's past imprudent actions by proposing a work schedule that would have been more "normal". ComEd should have performed some of the work that they did during 1999, 2000 and 2001 prior to that period.

The table below shows ComEd's major expenditures for 1998 through 2000 and projections for 2001. The first row shows ComEd's capitalized straight time for distribution plant. The second row shows ComEd's capitalized overtime for distribution plant.

Distribution Plant Expenditures
($1,000)

Years	1998	1999	2000	2001	1998-2001	1999-2001	Source
ComEd Straight Time	$ 68,635	$ 50,706	$ 67,500	$ 67,500	$ 254,341	$ 185,706	GEG 2.02
Overtime	$ 12,840	$ 25,114	$ 27,539	$ 27,539	$ 93,032	$ 80,192	GEG 2.02
Subtotal	$ 81,475	$ 75,820	$ 95,039	$ 95,039	$ 347,373	$ 265,898	
Proposed Disallowance		$ 4,091	$ 4,900	See Note 2 $ 231	$ 9,222		
Outside Contracts	$ 40,255	$ 77,165	$ 203,643	$ 203,643	$ 524,706	$ 484,451	GEG 2.07(1)
Capitalized Total	$ 239,191	$ 297,322	$ 688,348	$ 160,000	$ 1,384,861	$ 1,145,670	BAL 1.04

(1) Labor and Material
(2) Adjusted to percentage requested in this case

Staff Ex. 23.2.

Staff proposed limiting capitalized overtime for ComEd construction to the level of 1998. That represents approximately $40 million from 1999 through 2001. This is to reflect the fact that had ComEd rebuilt their system in a timely and controlled manner, there would not have been nearly as many overtime hours. Since the $40 million is primarily time and a half, one-third of that is Staff's proposed disallowance, or $13,329,000.

For ComEd's largest outside contractor, Asea Brown Boveri, ("ABB"), ComEd negotiated a contract that included incentive payments for completing construction in an expedited time period. Staff proposes to disallow these amounts because ComEd should have known that these facilities were needed before August of 1999, and could have contracted at appropriate earlier dates to build them at normal costs. The premium, expedited costs are totally a result of ComEd's imprudence in not maintaining and planning their system. The total amount for ABB and incentives for four other contracts is $16,293,000. Depreciation expense should also be reduced pursuant to both adjustments. Staff Ex. 9.0, pp.10-11.

In addition to the above time-based incentives, ComEd paid $449,000 for a transformer when a lower price was available but the vender could not meet ComEd's time requirements. This amount should be included with the above, for a total of $16,742,000. The grand total of disallowances of distribution plant based on imprudence is $30,071,000. Staff Ex. 23, p.12.

Staff's proposed adjustments do not remove all imprudent costs from ComEd's rates. There are many other areas where ComEd's imprudence led to increased costs. First, ComEd added numerous 138 kV transformers to increase its distribution system capacity. These transformers are generally long lead-time pieces of equipment. ComEd may have paid a premium for these transformers for delivery of so many in such a short time. Second, during the high heat of July of 1999, many pieces of equipment failed catastrophically or otherwise experienced a shortened lifespan from overloading. Staff has not recommended adjustments for these failures or loss of life. And third, many of the other outside contracts, while not having specified incentives for early completion, may have simply required early completion. There are likely many other areas where the immediate need for equipment and materials probably resulted in

ComEd having to pay higher costs. In addition, it is likely that a more controlled program over a longer time period would have been far easier to manage and resulted in more efficient project management. Staff Ex. 9.0, pp.11-12.

c. Request for Audit of New Distribution Capital Investment Costs

As previously noted, on November 30, 2001, Staff filed its Response to Petition for Investigation and Response to Motion to Dismiss in Docket No. 01-0664. In that pleading and the attached Staff Report, Staff recommended that the Commission initiate an audit and investigation of ComEd actions related to its transmission and distribution systems covering the period from 1993 through 2000, inclusive. Staff also recommended that the schedule in this proceeding be adjusted so that the results of the audit and investigation could be used by the Commission to determine a just and reasonable revenue requirement on the basis of a calendar year 2000-test year in this proceeding.

7. Other Rate Base Issues

D. Operating Revenues And Expenses

1. Recommended Operating Income Statement

2. Operating Revenues

3. Operating Expenses

a. Functionalization Of Generation, Transmission, And Distribution Expenses

b. A&G Expenses -- Direct Assignment and Allocation

A&G expenses should be functionalized according to the Commission's labor allocator, rather than the Company's proposed direct assignment approach.

The evidence in this proceeding clearly demonstrates that these expenses should be functionalized on the basis of the labor allocator. Many of the arguments for the labor allocator parallel the arguments presented with respect to General and Intangible Plant. However, there are additional reasons specific to A&G expenses that support the labor allocator for these accounts.

The arguments on behalf of the labor allocator for General and Intangible Plant equally apply to A&G expenses.

ComEd proposes to functionalize A&G accounts in a similar manner to General and Intangible plant using a combination of detailed direct assignments and allocation factors. Not only are the proposals similar, but so are the arguments. Furthermore, the deficiencies that appear in ComEd's proposed functionalization of General and Intangible Plant arise for A&G expenses. Because of the similarities, the Company's arguments for General and Intangible Plant also apply to A&G expenses. Those arguments are: (1) that the greater detail in ComEd's approach assures more accuracy; and (2) that ComEd's approach is consistent with its proposed approach in Docket No. 99-0117.

The inconsistencies far outweigh the consistency in ComEd's functionalization proposal.

ComEd's proposed functionalization methodology is riddled with inconsistencies at a variety of levels. First, the proposal is saddled with internal inconsistencies. Second, Mr. Hill's proposal is inconsistent with the Company's proposed methodology in Docket No. 99-0117. Third, the Company's proposal clearly conflicts with the methodology approved by the Commission in Docket No. 99-0117.

The Company's proposed functionalization of A&G expenses is inconsistent on many levels.

Despite Mr. Hill's claims, the Company's proposed functionalization of A&G expenses is inconsistent with the Company's proposal in Docket No. 99-0117. It also conflicts with the Commission Order in that case.

The differences with the Company proposal in Docket No. 99-0117 are demonstrated by a Staff analysis which compared the functionalization of A&G expenses to distribution in the two proceedings.

ComEd's proposed functionalization also conflicts with its proposed approach in Docket No. 99-0117.

Mr. Hill defends ComEd's proposed functionalization as consistent with its proposed approach in its previous case (Docket No. 99-0117). According to Mr. Hill, "ComEd has not changed from its prior method of functionalizing these costs" (ComEd Ex. 23.0, p. 7). However, Mr. Hill's claim is undermined by discrepancies between the two proposals.

As with General Plant accounts, Staff presented an analysis quantifying the inconsistencies between ComEd's A&G allocations in this case and Docket No. 99-0117 (Staff Ex 21, Schedule 21.1). For example, ComEd's proposed allocation of Account 920, Administrative and General Salaries, has increased by 35% from $43,781,651 to $59,195,368. The allocation of Account 921, Office Supplies and Expenses, has risen 32% from $40,476,161 to $53,303,145. The allocation of 925, Injuries and Damages, has climbed 248% from $3,464,745 to $12,067,800. For Account 935, Maintenance of General Plant, the allocation has risen by 137% from $3,337,390 to $7,912,424.

Furthermore, for Accounts 920-923, Mr. Hill acknowledged under cross-examination that the Company took divergent approaches in the two proceedings, using a number of employees allocator in this case but not in Docket No. 99-0117 (Tr. 3222-3223 and 3428). This acknowledgement underscores the differences between the two studies.

As with General and Intangible Plant, the most important consistency issue for A&G expenses concerns the consistency of the Company's proposal with the Commission Order in Docket No. 99-0117. This issue is key because the Commission, not the Company, determines the appropriate allocation of these accounts. In its Order, the Commission concluded as follows with respect to A&G accounts:

> While direct assignment may be a better method in some cases, the Commission does not believe costs, which include CEO and executive salaries, are amenable to direct assignment. Were such costs amenable to direct assignment, Edison would have assigned these costs directly to the distribution function in prior cases. Edison did not. For the same reasons that we disagreed with Edison's direct assignment of General Plant costs, we also disagree with Edison's direct

> assignment of A&G expenses. We, therefore, adopt IIEC's proposal for allocation. Order, p. 27.

This decision is striking because of the breadth of the Commission's conclusion on these issues. The Commission objected, not just to ComEd's specific proposal in the case, but to the general concept of functionalizing these accounts on the basis of direct assignments.

Nevertheless, as with General and Intangible Plant, ComEd has failed to heed the Commission on this issue. ComEd proposes to use the same direct assignment approach in this case that the Commission rejected in no uncertain terms in Docket No. 99-0117.

If anything, the Company relies more heavily on the direct assignment approach in this proceeding. For example, in Docket No. 99-0117, ComEd functionalized $82 million (40%) of the $206 million in Accounts 920-922, Salaries and Wages, Office Supplies and Expenses and Administrative Expenses Transferred based on direct assignments (ComEd Ex. 5.0, p. 2). The Commission in its Order expressly criticized the use of direct assignments for this category of costs, stating "the Commission does not believe costs, which include CEO and executive salaries, are amenable to direct assignment" (Order, p. 27).

Despite the Commission's unambiguous conclusion, ComEd proposes in this proceeding to directly assign a total of $187 million out of the $254 million in these accounts. That represents 74% of the costs in these accounts, a significant increase from the 40% ComEd had proposed in Docket No. 99-0117.

ComEd's efforts to justify this divergence from Commission precedent lack foundation.

The argument presented by Company witness Hill to explain ComEd's failure to heed the Commission's conclusions for General and Intangible plant also applies to A&G expenses. That argument contends that changes in the Company's business structure during the test year undermine the relevance of the Commission's Order in Docket No. 99-0117 for the current proceeding.

As with General and Intangible Plant, Mr. Hill's argument is unpersuasive for A&G accounts. ComEd's decision to reorganize provides no justification to abandon the Commission's decision on this matter. Mr. Hill's restructuring argument does not address the general concern by the Commission about the use of direct assignments for these accounts. The Commission did not suggest that it opposes direct assignments only for a utility structured along vertical lines. Therefore, ComEd's restructuring has no bearing on the Commission's conclusion for these accounts.

As with General and Intangible Plant, Mr. Hill uses this reorganization as a tool to shift costs from generation to distribution and thereby penalize delivery services ratepayers in the process. ComEd certainly may realign its business structure for its own purposes but it should not be done at ratepayers' expense.

Furthermore, Mr. Hill's argument concerning ComEd's restructuring is flawed because the Company did not even begin to restructure until after the test year ended in January 2001 as was explained with respect to General and Intangible Plant (ComEd Ex. 4.0, Appendix A, p. 1; Tr. 3210-3211). This discrepancy undermines the foundation for ComEd's proposed functionalization in this case.

Approval of the Company's proposed functionalization methodology for A&G expenses would produce a double standard for Illinois utilities.

In contrast to ComEd, other Illinois utilities such as AmerenUE and AmerenCIPS have adhered to the Commission-approved labor allocator for functionalizing A&G expenses in this round of delivery services cases. If the Commission accepted ComEd's proposal in this case, it would be applying a double standard in favor of those utilities that disregard Commission opinions over utilities that adhere to those opinions. That would be a dangerous precedent indeed.

Staff's proposed functionalization methodology for A&G accounts should be adopted in this proceeding.

As explained with respect to General and Intangible Plant, Staff has proposed an adjustment in this proceeding based on applying the labor allocator adopted by the Commission in Docket No. 99-0117 to the functionalization of General and Intangible Plant in this proceeding. Staff is joined by IIEC and the City in proposing adjustments to the functionalization of General and Intangible Plant and A&G expenses based on the Commission-approved labor allocator. However, their proposed adjustments fall short for A&G accounts because they do not take into consideration the fossil plants sold by ComEd prior to the test year.

Staff's labor allocator proposed for General and Intangible Plant should be used for A&G expenses as well.

Staff's proposed labor allocator differs from the proposals by the City and IIEC because it includes the labor associated with the fossil plants that ComEd divested before the test year. The reason for using this fossil labor, as explained with respect to General and Intangible Plant, stems from the Commission Order in Docket No. 99-0117 which adopted a labor allocator that included labor from ComEd's fossil plants. However ComEd fails to properly adjust A&G expenses downward when it sold those plants to Mission Energy in November 1999, thereby laying the groundwork for higher delivery services rates.

This increase is particularly inappropriate considering that the decision to sell those plants was the Company's alone and the $4.813 billion received from that sale went to the Company, not ratepayers. Given ComEd's tangible benefits from the sale, ratepayers should not be penalized by a reallocation of A&G account balances to delivery services.

The Company's failure to appropriately allocate A&G expenses also conflicts with its assurances that the sale of fossil plants would benefit customers and other parties with an interest in a more competitive generation market. ComEd Notice of Property Sale, May 12, 1999, p. 6. The higher delivery services rates that result would make delivery services a less attractive alternative to bundled rates and hinder, rather than advance, competition.

The specific adjustment proposed by Staff for A&G expenses is reasonable and should be adopted.

As previously noted, the specific adjustment proposed by Staff covers both General and Intangible Plant and A&G expenses. Furthermore, as has already been indicated, the application of Staff's proposed labor allocator that includes labor from the divested fossil plants produces adjustments of: $(405,160,914) in Gross Plant; $1,035,274 in Depreciation Reserve; $555,976 in ADIT and Other Rate Base Items; and $(60,002,014) in expenses. The proposed adjustment reflects the difference in the revenue requirement that results from using a labor allocator to functionalize General and Intangible Plant and A&G expenses in the Company's cost of service study.

Staff's proposed labor allocator, which has been previously described with respect to General and Intangible Plant, begins with the labor allocator contained in the Company's cost of service study and substitutes the production labor figure from the Company's 1999 FERC Form 1 (p. 354, line 18) for the production labor amount in the Company's cost of service study. This increases the production component of the allocator from $448,246,408 to $538,203,725 and decreases the distribution share of labor from 36.94% to 33.06%. The 1999 figure was used because it represents the most recent year that ComEd included labor costs from the fossil plants. This is the most reasonable figure to use to reflect the role of the fossil plants in the labor allocator. The development of the proposed adjustment is presented in Staff Ex. 21.0, Schedule 21.2.

c. Proposed Known & Measurable Changes to Test Year Expenses

i. Expense Adjustments Related To Rate Base Adjustments

ii. “Levelization” Adjustments

A. Tree Management Expense

Staff witness Jones proposed an adjustment to reduce test year tree management operating expense by $7,028,000 based on an eight-year average of historical expense (indexed for inflation) for the years 1993 through 2000. (Staff Exhibit 2.0, p. 9 and Schedule 2.6) Theoretically, the rates set in this case are set in perpetuity and should reflect normal operating conditions; i.e., a normal, recurring level of expense to maintain the four-year tree trimming cycle to which the Company says it is now committed. As Ms. Jones pointed out in her Direct Testimony, the three-year average calculated by the Company in an attempt to normalize tree management expense in the test year is not based on years with normal levels of tree management activity. The Company’s average is based on years in which an accelerated tree trimming program to catch up to a four-year tree trimming cycle was in effect. (Staff Ex. 2.0, p. 8)

According to Company witness Voltz, from October 1998 to May 2000 the Company was on an aggressive program to establish and maintain a four-year tree trimming cycle. (Tr. 1992) However, the Company could not identify that portion of the actual expenses incurred in 1999 and 2000 to catch up to a four-year cycle as opposed to that portion of the expenses needed to maintain a four-year cycle as a normal level of tree trimming activity. (Staff Ex. 16.0, p. 8)

The normal level of expense to maintain a four-year tree trimming cycle is simply unknown. Presumably, the volume of tree trimming activity and the associated expense would decline once the four-year cycle was achieved. In fact, that is what the Company expected to happen. In Docket No. 99-0117, Company witness Kathryn M. Houtsma testified that tree trimming expense was projected to decrease in year 2001 from year 2000 levels. (Staff Ex. 16.0, p. 10)

The eight-year average of historical expense (indexed for inflation) for the years 1993 through 2000, which Staff witness Jones used in her proposed adjustment, provides a more realistic level of normal tree trimming expense than does the Company's average for the years 1998, 1999, and 2000. It smoothes the effects of the significantly higher expense incurred in 1999 and 2000, when the majority of the accelerated tree trimming program was in effect, yet allows the Company to recover considerably more than the $35,380,000 tree-trimming expense projected for 2001 in Docket No. 99-0117. (Id.) Consequently, Ms. Jones' adjustment is just and reasonable and should be accepted.

B. Storm Restoration Costs

Staff Witness Sant proposed an adjustment to further reduce the Company's storm restoration expense to reflect a more normal level in the test year revenue requirement. This normalization adjustment is necessary considering the Company's proposal is over three times higher than the average for the years 1993 – 1997, which was the period utilized in Docket No. 99-0117. The Company's proposal in this docket uses an average of the years 1998 – 2000.

The Company disagrees with Staff's proposed adjustment because it believes that its three-year average is more than an adequate time period to determine normality. The Company also believes 1993 – 1997 data cannot be compared to post-1997 data because of a change in accounting system and in storm restoration operations. The

Company also deems Staff's annualization of 2001 data to be inappropriate. ComEd's proposed three year period from 1998 – 2000 is not an adequate time period in which to derive the test year storm restoration expense. ComEd has not supported the sufficiency of its proposed three-year average. The Company asserts that pre-1998 data is not comparable to post-1997 data because of the changes it has made to its accounting system and storm restoration operations. (ComEd Ex. 46.0, pp. 19 – 20, l. 415 – 433) Storm restoration expense amounts for the three years following these changes show incredible fluctuation. The total amount decreases by nearly 55% from 1998 to 1999, and then increases by approximately 81% from 1999 to 2000. In dollar terms, there is a $20 million decrease in 1999 from the 1998 level and then a $13.4 million increase in 2000. (ICC Staff Exhibit 17.0, Schedule 17.7, p. 2) With such a short time period reflecting such incredible fluctuation, it is not appropriate to determine any kind of trend.

The Company's alternate proposal to use the forty-four month period of 1998 through the first eight months of 2001 only exacerbates the tremendous fluctuation. (ComEd Ex. 46.0, p. 20, l. 437 – 438) There is approximately a 62%, or $18.6 million decrease that occurs from 2000 to an annualized 2001 amount. (ICC Staff Exhibit 17.0, Schedule 17.7, p. 2) It is not determinable whether 1998 and 2000 are high outliers or whether 1999 and especially 2001 are low outliers. With such variation, it is especially important to have a longer time period to determine a more normal recurring amount. Therefore, neither the three-year average of 1998 – 2000 nor the alternate forty-four month average reflects an ongoing normal level of expenditures.

The Company is incorrect that 1993 – 1997 data cannot be compared to post-1997 data because of a change in accounting system and in storm restoration operations. As Company witness Voltz testified at the evidentiary hearing, there is actually a third phenomenon that possibly plays a role in the increase in storm expense, and that is the natural fluctuations of storm intensity and damage. (Tr. 1958 - 1959) Neither a three-year period nor a forty-four month period can capture the natural fluctuations in resulting storm restoration expense for the test year.

The Company has repeatedly postulated that there may be storm costs in the 1993 – 1997 period that the old accounting system did not record as storm related but that the new system would. (ComEd Ex. 24.0, p. 19, l. 384 – 385 and ComEd Ex. 46.0, pp. 19 – 20, l. 422 –424) The Company did provide Staff with total amounts for the years 1993 – 1997, and did not disclaim any of the years as not being the total recorded amount of storm expense. (Tr. 2002 - 2003) Because the Company may or may not have extra storm restoration costs in the years 1993 – 1997, and because of the difficulty the Company has in determining the effect new storm restoration operations has on storm restoration costs, we are left to wonder how much of the tripling of storm restoration expenses from the prior delivery services tariffs is simply due to 'mother nature.' Admittedly, the Company has not quantified how much any of the three factors have contributed to the increase in the level of storm restoration expense. (Tr. 1960) If the Company believes there are shortcomings in the information it has and the Company is unable or unwilling to provide more comparable information, then any shortcomings resulting from the use of that information should be construed to the detriment of the Company before it is construed to the detriment of the ratepayers.

Staff believes that when normalizing storm restoration expense it is necessary to normalize the total costs, not just the variable costs, as proposed by the Company. What the Company defines as "fixed" storm costs varies to the same degree as the variable costs and overall storm restoration costs during the time period 1998 – 2000. The amounts for 1998 through 2000 of fixed storm expense, respectively, are $17.5 million, $7.0 million, and $11.2 million. This represents an approximate decrease of 60% in 1999 and then another approximate increase of 60% in 2000. (Tr. 1962 & 1964) Comparing the three years' fixed costs, they are as erratic as the Company's variable, or incremental costs. As the Company repeatedly states, storms are highly variable. Obviously, so are the fixed storm costs. It is not sound reasoning to therefore normalize the incremental costs and not the fixed costs. The Company has explained why it is only proposing a normalization of the variable expense, yet it is not clear whether the Company opposes the normalization of the total cost rather than just the variable cost. (ComEd Ex. 46.0, p. 21, l. 452 – 461)

Staff simply finds it incredible that the Company would take the position that three years of data is <u>more than adequate</u> in determining a reasonable amount of storm restoration expense when that level is more than triple the normalized amount used in the current delivery services tariffs.

C. Reserve for Levelized Variable Storm Damage Expenses

Staff opposes the Company's proposed storm reserve with accompanying reconciliation. The Company's reconciliation proposal constitutes single-issue ratemaking; it violates test year principles; and, it would constitute retroactive ratemaking when over- or under- recoveries are reflected in future rates. For these reasons, the Commission should reject the Company's proposal. (ICC Staff Ex. 3.0, p. 17, l. 336-340)

Single-issue ratemaking occurs when revenues are based on the consideration of one component of the revenue requirement in isolation rather than on the aggregate expenses of the utility company. This is inappropriate because it can overlook the fact that sometimes increases in one expense correspond with decreases in other expenses.

In the Company's proposal for a storm reserve, the revenue requirement used in the rate formulation in the ensuing rate cases would include an amount for storm expense that is either increased or decreased based solely upon the balance in the storm reserve due to the activity in preceding years. Other increases and decreases in the various operating and maintenance expense accounts that are directly or indirectly affected by storm expenses would not be considered when reconciling the storm reserve. (ICC Staff Ex. 3.0, pp. 17-18)

In Business and Professional People for the Public Interest v. Illinois Commerce Commission, 146 Ill.2d 175, (1991) ("BPI II") the Illinois Supreme Court described single-issue ratemaking as follows:

> The rule against single-issue ratemaking recognizes that the revenue formula is designed to determine the revenue requirement based on the aggregate costs and demand of the utility. Therefore, it would be improper to consider changes to components of the revenue requirement in isolation. Oftentimes a change in one item of the revenue formula is offset by a corresponding change in another component of the formula.

Id. at 244. The Court uses an example of an increase in depreciation expense that may be offset by a decrease in the cost of labor because of improved productivity or increased demand in electricity. Then it gives this conclusion on why single-issue ratemaking is not appropriate:

> In such a case, the revenue requirement would be overstated if rates were increased based solely on the higher depreciation expense without first considering changes to other elements of the revenue formula. Conversely the revenue requirement would be understated if rates were reduced based on the higher demand data without considering the effects of higher expenses.

Id., 244 -245. This is exactly what would be happening when the Company reconciles its storm reserve using an over- or under-recovery for a period that is separate from the period used for normalizing storm expense. As the Company proposes to reconcile the normalized storm amount based purely on the over- or under-recovery of storm expenses, the Company is clearly not considering its operating expenses and revenue in the aggregate in that period.

The proposal violates the test year principle because it would take data concerning storm expense from many years through its proposed reconciliation process, and match it with revenue from one year, i.e. the test year. Quite often, data from many years is used to normalize an expense. However, the reconciliation process proposed by the Company is not to normalize a test year expense, rather, it is to adjust the normalized expense by the over- or under-recovered amount of the storm reserve. This process could easily facilitate the mismatching of high expense data from one year and low revenue data from another year. (ICC Staff Ex. 3.0, pp. 18-19) BPI II stated the following with regard to test-year principles:

> As previously stated, a utility's rates are a function of its annual revenues and operating expenses, as well as its rate base. In order to accurately determine the utility's revenue requirement, the Commission established filing requirements under which a utility must present its rate data in accordance with a proposed one-year test year. The purpose of the test-year rule is to prevent a utility from overstating its revenue requirement by mismatching low revenue data from one

> year with high expense data from a different year. Business & Professional People for the Public Interest v. Illinois Commerce Comm'n, 136 Ill.2d 192 at 219.

BPI II, at 240. The Company's proposal is to adjust a normalized test-year amount by data unrelated to the test-year (the over- or under-recovered amount). Besides violating test-year principles, Staff witness Sant explained in his rebuttal testimony how it's possible that this proposal would allow the Company to overstate its revenue requirement by mismatching low revenue data from one year with high expense data from a different year, which, as stated above, is a concern of the Illinois Supreme Court. As stated in Mr. Sant's rebuttal testimony, it is certainly possible that the reconciliation period contains high expense data, and an under-recovery from that period is applied to the test-year, which may be a low revenue year. (ComEd Ex. 17.0CR, p. 16, l. 313 – 322)

The Company disagrees by simply stating that, "the proposal over time reduces, not increases, 'mis-matching'". (ComEd Ex. 46.0, p. 26, line 561) The Company does not explain how the "mis-matching" is decreasing. The same Company witness submitted the following testimony:

> Mr. Sant's suggestion that "[t]his process could easily facilitate the mismatching of high expense data from one year and low revenue data from another year" (Staff Ex. 3.0, page 19, l. 370-371) appears to reflect a misunderstanding of the proposal or else a failure to acknowledge that the proposal by its very nature over time does the opposite of what Mr. Sant appears to be concerned about. The proposal over time levelizes the recovery of variable storm expenses. The principle of "normalizing" expenses is a common practice that is applied to variable expenses such as variable storm expenses to provide an average expense component during some defined time period. (ComEd Ex. 24.0, p. 22, l. 453 – 461)

This testimony indicates that the Company believes that levelizing or "normalizing" the recovery of storm expenses lessens the mismatching discussed previously. However, no lessening is evident as the mismatching is occurring when the over- or under-recovery is combined with a normalized test-year amount.

ComEd's proposed storm reserve is in essence retroactive ratemaking. Increasing the expense for under-recovery of the expense would allow the Company to recoup prior deficits. Conversely, decreasing the expense for over-recovery of the storm expense is specifically the act of refunding to ratepayers the excessive profits. The Supreme Court has held "the Act does not permit retroactive ratemaking; that is, the law prohibits refunds when rates are too high and surcharges when rates are too low. Citizens Utilities Co. v. Illinois Commerce Commission, 124 Ill. 2d 195, 207" Business and Professional People I, 136 Ill. 2d 192, 209 (1989).

ComEd's proposal of reconciling the storm reserve is precisely what the previous cases have described as allowing the utility to recoup prior losses, or refund excessive profits. If an under-recovery occurs, then by increasing the normalized test year storm expense to recover the under-recovered reserve amount, it is clearly a case of allowing the utility to recoup prior losses. Conversely, if the reserve is in a state of over-recovery, the negative adjustment to the normalized test-year storm expense amount would just as clearly be the utility refunding excessive profits to the ratepayers.

The Company acknowledges the retroactive nature of its proposal:

> The purpose of the storm reserve account would be to provide a means to not only normalize but reconcile the levelized retrospective view of expenses incurred during the period between ratemaking proceedings. (ComEd Ex. 46.0, p. 23, l. 482 – 485) (emphasis added)

Rather than discuss the problems inherent in retroactive ratemaking, it simply chooses to state that the merits of the proposal (in the interest of the Company, ratepayers, and alternative suppliers) make it worthy of acceptance by the Commission. (ComEd Ex. 46.0, p. 26, l. 564 – 571)

Staff reminds the Commission that the equality of the "merits" among the Company, ratepayers, and alternative suppliers is debatable. For instance the Company has argued that this proposal would stabilize earnings, which would lower the cost of capital, which benefits the ratepayers as well as the Company. However, the Company does not mention that this proposal also allows shareholders to recover the storm restoration expense portion of the revenue requirement risk-free. This certainly is strictly a benefit to the shareholders, not to the ratepayers, nor to the alternative suppliers. (ICC Staff Ex. 17.0CR, pp. 18 – 19, l. 355 – 363) However, what is not debatable is that the prohibition against retroactive ratemaking is a fundamental tenet in utility ratemaking.

For all the foregoing reasons, the Commission should reject the Company's proposal.

D. Other

i) Distribution Salaries and Wages[2]

Staff is proposing a normalization adjustment for distribution salaries and wages expense. This adjustment is to decrease the salaries and wages to a more normal level. The test year reflects a significant increase in distribution salaries and wages. When Staff questioned the Company concerning the sustaining of this level of expense the Company chose to indicate that it did not know whether this level of expense will continue. (ICC Staff Ex. 14.0, p. 3, l. 52 – 57)

Unless the extraordinary actions the Company undertook as part of this reliability upgrade program are to continue indefinitely, any effects of the reliability program upon the test year distribution wages and salaries expense call into question whether the test year amount reflects a normal, ongoing level. Staff is not aware of any attempt by the Company to remove from its test year distribution wages and salaries expense any of the effects of this reliability upgrade program, nor has the Company attempted to explain the necessity or the recurring nature of over $26 million of the increase from before this unprecedented upgrade began to the test year.

Because doubts surrounding the normal level of expense in the test year stem from the maintenance upgrades embarked on by the Company, Staff used 1998 as a base year for calculating the adjustment because it predates the reliability upgrades. Staff's test year normalized amount is calculated by increasing 1998 salaries by a typical amount of wage inflation for two years. This amount is then compared to the test year amount proposed by the Company. The difference, less variances related to refunctionalization of costs and the new recording method for incentive compensation, is the foundation for Staff's adjustment. (ICC Staff Exhibit 17.0CR, Schedule 17.12, l. 1 – 7) However, Staff also reduces its proposed adjustment by amounts that may be considered double-counting because of other proposed adjustments by the Company and by Staff. (Ibid, l. 8 – 12)

The Company responds that "there is no reason to believe that 1998, a year before the Company's enduring changes, represents a normal year for distribution salaries and wages." (ComEd Ex. 46.0, p. 11, l. 229 – 231) Staff maintains that this

[2] Addition to ALJ outline

argument is inconsistent because Company witness Voltz, in talking about distribution maintenance programs and expenses, which would include distribution salaries and wages, appears to imply that 1998 is normal in relation to the test year. (ICC Staff Ex. 17.0CR, pp. 38 – 39, l. 773 – 793) The Company argues against this point, in Mr. Voltz's surrebuttal testimony by stating:

> Mr. Sant seems to be implying that because I have argued or shown in certain circumstances that 1998 is not wholly different from 2000, that I have implied that 1998 is a normal year. He takes my comments out of context. In order to improve the reliability of the system, ComEd has made many substantive enduring changes to various distribution planning, operation, and maintenance practices. (ComEd Ex. 46.0, p. 11, l. 223 – 227)

Mr. Voltz's testimony speaks for itself and is not taken out of context. Mr. Voltz, in opposition to proposed adjustments by intervenors, states that O&M expenses in the test year are not abnormally high because most of the various maintenance programs were carried out for numerous years. (ComEd Ex. 24.0, p. 12, l. 236 – 249) If 2000 distribution O&M expenses are not abnormally high because most maintenance programs have been carried on for numerous years, it is not out of context to state that this witness is being inconsistent by then testifying that 1998, just two years prior to the test year, is abnormal when it comes to distribution salaries and wages expense.

Furthermore, the Company's argument states that to improve the reliability of its distribution system, it has made many substantive enduring changes to various distribution planning, operation, and maintenance practices. Staff repeats its two concerns with distribution salaries and wages expense. First of all, Staff does not know, and the Company has not attempted to satisfy Staff's questions concerning the recurring or 'enduring' nature of its higher level of distribution salaries and wages expense. Second, the concern that any effects of the unprecedented reliability upgrade program upon the test year distribution wages and salaries expense calls into question whether the test year amount reflects a normal, ongoing level of expense.

iii. Salary and Wage Adjustment for General Pay Increases

The Company has proposed a pro-forma general pay increase adjustment due to new labor agreements. This increase is calculated by applying 3.5% to salaries and wages. To the extent that Staff's salaries and wages adjustments are accepted by the Commission, an additional 3.5% adjustment must be approved to offset the Company's pro-forma adjustment. Staff has incorporated this additional 3.5% into each of its salaries and wages adjustments. (ICC Staff Exhibit 17.0CR, p. 30, l. 602 – 615) The Company has not contested this aspect of Staff's adjustments.

iv. Adjustments for Post-Test Year "Merger Savings"

<u>Bill Payment Centers</u>

Staff is proposing to decrease customer accounts expense to reflect the closing of certain bill payment centers by the Company. These closings occurred after the test year, thus an adjustment is necessary to reflect the decrease in operating expenses. (ICC Staff Ex. 3.0, p. 20, l. 338-395; ICC Staff Ex. 17.0, pp. 20-24, l. 392-481)

The Company has identified two bill payments centers that closed in 2001. The Company has also quantified the savings that will be achieved from having customers mail in their bills rather than using these former payment centers. The closing of these bill payment centers constitutes a known and measurable adjustment to test year operating expenses.

The Company takes issue with this adjustment stating that these closings are merger savings, which the Company states should not be used to adjust test year expenses. The Company's basis for this position is that merger costs have already been excluded in the adjusted test year by the Company and merger savings are already reflected in the adjusted test year. (ComEd Ex. 23.0, pp. 26 & 28, l. 568 – 572, 605 – 609)

The Company's position suffers from at least three flaws. First, the Company has never established or provided support for the position that there is a relationship between its merger with PECO and the closing of these two bill payment centers.

Second, even if these closings are in fact related to the merger, the exclusion of merger costs from the adjusted test year does not indicate that merger savings are also automatically excluded. In several cases, including those set forth below, the Commission has ordered that merger costs are not to be collected from ratepayers. Furthermore, in the last three cases set forth below, the Commission excluded the recovery of merger costs, while at the same time, ordering that the full amount of merger savings be passed-through to the ratepayers:

Illinois-American Water Company 00-0340 Proposed general increase in water rates;

United Cities Gas Company 00-0228 Proposed general increase in gas rates;

Central Illinois Public Service Company and Union Electric Company 99-0121 Petition for approval of delivery services implementation plan and delivery service tariffs;

Union Electric Company 98-0456 Proposed general increase in gas rates;

Central Illinois Public Service Company 98-0455 Proposed general increase in gas rates; and

Central Telephone Company of Illinois 93-0252 Proposed increase in local service rates.

Third, the facts contradict the Company's assertion that merger savings are already reflected in the adjusted test year. The only merger adjustment the Company proposed is to deduct implementation and integration costs from the test year expenses. These costs, incurred in 2000, are quantified and reflected in ComEd Ex. 4.0, Schedule C-2.5. On the other hand, the operating expense savings for the bill payment center closings, absent some further Company pro forma adjustment which is lacking, are not reflected at all in the test year data as the closings did not take place until July 2001.

Ratepayers should not be burdened with funding operating expenses that support the operation of bill payment centers that no longer exist. These closings represent a known and measurable change to test year operating expense. Therefore, the Commission should accept Staff's adjustment decreasing operating expense for the closing of two bill payment centers.

<u>Layoffs</u>

Staff proposed an adjustment to reflect a known and measurable reduction of 154 employees. The Company has made several separate announcements pertaining to layoffs. Due to redundancies from the merger with PECO, the Company has announced layoffs of 292 employees (154 jurisdictional). The Company has announced further merger-related layoffs of 2,900 (1,061 jurisdictional). (GCI Redirect Ex. No. 42)

Furthermore, the Company recently announced layoffs, economic-related rather than merger-related, of an additional 450 (jurisdictionally undetermined) employees. Staff proposed an adjustment to salaries and wages expense for the 154 employees whose discontinuation of employment with the Company is both known and measurable. The Company acknowledged that these specific layoffs occurred in September 2001, well within the known and measurable adjustment window. (ComEd Ex. 23.0, p. 27, l. 586 – 588). Staff quantified this adjustment based upon information provided by the Company.

The Company argues that it is not appropriate to deduct "merger savings" because they have already been reflected in the Company-adjusted revenue requirement and merger costs were excluded from the revenue requirement. (ComEd Ex. 23.0, p. 26, l. 565 – 572) The Company also contends that severance costs related to these layoffs need to be factored into the computation because it is only fair to recognize the costs incurred to achieve the savings. (ComEd Ex. 23.0, p. 27, l. 590 – 591 and Ex. 45.0, p. 40, l. 862 – 864) The Company bases this "fairness" issue on the following assumptions: 1) non-merger related severance costs are recoverable in revenue requirements; 2) layoffs benefit the ratepayers (merger savings flowing directly to them) so the costs to obtain those benefits are the responsibility of the ratepayers; and 3) if the costs are a lump-sum, it is entirely appropriate to amortize it over a reasonable period. (ComEd Ex. 45.0, p. 40, l. 853 – 864)

As previously pointed out, the Company's argument that merger savings should be excluded because merger costs have been excluded is inconsistent with several prior Commission Orders. The Commission has ordered that merger costs are not to be collected from ratepayers. Also, the Commission has excluded the recovery of merger costs, while at the same time, ordering that the full amount of merger savings be passed-through to ratepayers.

Also, as previously stated, the record of evidence in this proceeding does not show that merger savings are already reflected in the adjusted test year. The only merger adjustment proposed by the Company is implementation and integration costs which has been deducted from the test year expenses. The operating expense savings related to these 154 employees are not reflected at all in the test year data, as the layoffs did not take place until after the test year.

The Company's contention that severance costs related to these layoffs need to be factored into the adjustment is flawed as well. First, as the Company states "it is only fair to recognize the costs incurred to achieve the savings," it would then conversely also be "fair to recognize" that after the eight months of severance costs, these specific costs do not recur. As pointed out by Mr. Hill, the Company will not realize actual savings, i.e. no more severance costs, until mid-2002. This is not only within the twelve month window required for known and measurable adjustments, but it is also within the first months that the delivery service tariffs are in effect. Also, these savings represent a recurring reduction in operating expenses for the Company, unlike the nonrecurring severance costs.

Staff also finds the fairness issue the Company uses to argue for the adjustment to be offset by severance costs unconvincing. For instance, the Company states that non-merger related severance costs are recoverable in revenue requirements. This recoverability is based on the notion that these expenses are normal and recurring.

Presumably there is already a normal recurring amount of severance costs in the test year reflected in the operating statement. However, the severance costs in question are not normal and recurring, but based upon a distinct event.

The Company also pleads fairness by stating that layoffs benefit the ratepayers, i.e. merger savings flowing directly to them, so the costs to obtain those benefits are the responsibility of the ratepayers. However, the Company fails to mention that for several months following the scheduled layoffs, the severance costs are effectively negated by the reduced wages expense. Therefore, the responsibility for these costs has presumably been met by the ratepayers since the rates currently being paid are structured for the funding of salaries and wages. Because the responsibility would have already been paid by the ratepayers, it is inappropriate to amortize this lump sum of estimated severance as also suggested by the Company.

Furthermore, the Commission has previously identified employee severance costs as "transactional" costs that are to be excluded from the revenue requirement. (Ameritech/SBC Docket No. 98-0555 Amendatory Order on Rehearing November 15, 1999) Therefore, it is entirely consistent with Commission practice not to factor in the severance costs while adjusting operating expenses by a recurring decrease in labor expense due to merger layoffs.

As the Company has announced several additional rounds of layoffs, some related to the merger and some not, it is reasonable to assume that the Company's labor costs will be substantially decreasing. Yet, Staff has only proposed an adjustment relating to the one round of layoffs that is clearly known, measurable and quantifiable.

Staff therefore believes the Company's arguments relating to the fairness of this adjustment to be quite disingenuous.

d. Other Proposed Adjustments to Expenses

i. Exclusion of Incremental Expenses Related to Unicom/PECO Merger

ii. Exclusion of Audit-Related Costs

iii. Environmental Remediation Expenses

iv. Advertising Costs

Staff disallowed advertising costs which: 1) are not recoverable under Section 9-225 of the Act, 2) are not properly includible in the 2000 test year; and 3) are for an advertising campaign that was cancelled. (ICC Staff Ex. 4.0, p. 4) (Tr. 1764-1765)

Staff Witness Bowers eliminated categories of advertising that are not recoverable under Section 9-255 of the Act. (ICC Staff Ex. 4.0, p. 4) "Goodwill or institutional advertising" means any advertising either on a local or national basis designed ***primarily*** (emphasis added) to bring the utility's name before the general public in such a way as to improve the image of the utility or to promote controversial issues for the utility or industry." Staff Witness Bowers eliminated from the test year the costs of certain advertisements that appear ***primarily*** to bring the Company's name before the public. (Attachment A to ICC Staff Ex. 18.0) The purpose of these advertisements appears to be to deflect the ratepayers' attention from the numerous outages ComEd has had in the past and reassure the ratepayers that the outages will not happen as often in the future. In essence, trying to gain the ratepayers' goodwill.

Ms. Bowers' adjustment also removed from the test year certain costs that were reflected in December of the 2000 test year, but which actually pertained to January of 2001, the subsequent year. (ICC Staff Ex. 4.0, p. 4, l. 86-89) In addition, Ms. Bowers' disallowed an advertising campaign the Company cancelled after the costs had been incurred. The ratepayers should not have to cover the Company's change of direction or error. (ICC Staff Ex. 4.0, p. 4, l. 85-86).

v. Bank Commitment Fees

Staff Witness Bowers proposed an adjustment to disallow $902,000 of bank commitment fees because the fees are a form of interest expense, which is considered a "below the line item". One purpose of these fees is to provide lower interest rates upon taking advantage of these credit lines. (ICC Staff Ex. 18.0, p. 8, l. 163-164) The Company responded that bank commitment fees are normal, necessary bank charges paid in association with lines of credit. (ComEd Ex. 45.0, p. 26, l. 553-554) However, the Company acknowledged that bank commitment fees are associated with credit arrangements, which support the overall capital structure of ComEd. (ComEd Ex. 23.0, p.013, lines 288–289). The Company further acknowledged that the lines of credit serve to lower the cost of obtaining certain types of debt. (ComEd Ex. 45.0. p. 26, l. 560-562)

vi. Legal Expenses

Staff Witness Bowers proposed an adjustment to reduce legal expenses by $3,653,000 to include only costs that are related to jurisdictional delivery services. (ICC Staff Ex. 18.0, pp. 11-13)

Staff Witness Bowers described the difficulty she had in obtaining information from the Company sufficient to evaluate the legal expenses, as set forth on what eventually became ComEd Cross Exhibit 29. (ICC Staff Ex. 4.0, pp. 7-8; and ICC Staff Ex. 18.00, p. 11, l. 240-247) Accordingly, Staff Witness Bowers identified four (4) options for determining an amount to be included in the revenue requirement for legal expense. (ICC Staff Ex. 18.00, p. 11, l. 258-260 and Tr. 1755) Staff Witness Bowers further testified that of the four (4) options, Option # 4 was most preferable. This option used the Company's allocator to assign to delivery services only those items that appeared to have some relationship to delivery services (Tr. 1753-1756).

vii. Charitable Contributions & Memberships

Charitable Contributions:

Staff Witness Bowers disallowed contributions to organizations outside the Company's service territory because ratepayers should not bear the burden of expenses that provide them with no benefit. (ICC Staff Ex. 4.00, pp. 3-4)

ComEd Witness Hill acknowledged that ComEd's first principle mission for these contributions was for organizations that serve communities within its Northern Illinois service territory (Staff Cross-Ex. 76, Tr. 3233). The Company argues that benefits fall to delivery service customers from those contributions Staff Witness Bowers proposed to exclude. (ComEd Ex. 45.0, p. 27) However, the Company was unable to provide examples of any ratepayer receiving these perceived benefits.

Staff Witness Bowers adjustment is appropriate because ratepayers should not be burdened with expenses that provide them with no benefit. ComEd has even acknowledged that this approach is consistent with its purpose for making charitable contributions. (ICC Staff Ex. 18.00, p. 9, l. 198-200)

Memberships:

Staff Witness Bowers disallowed organizational dues other than to the Edison Electric Institute. (ICC Staff Ex. 4.00, page 6 and ICC Staff Exhibit 18.0, p. 10). The Commission has repeatedly found that shareholders, rather than ratepayers, should bear these expenses. (Commission Order dated March 8, 1991, ComEd Docket No. 90-0169, p. 36; Commission Order dated January 9, 1995, ComEd Docket No. 94-0065, p. 39-40; Commission Order dated August 25, 1999, CILCO Docket Nos. 99-0119 and 99-0131 (Consolidated), pp. 32-34)

viii. Special Projects

Staff Witness Bowers proposed an adjustment of $1,174,000 to Special projects because, based upon information provided by the Company, she understood these costs to be related to generation.

ComEd's cross-examination of Staff Witness Bowers raised the issue of double counting between this proposed adjustment and her proposed adjustment to Research and Development costs. Staff Witness Bowers testified that she could not make a careful analysis of the documents provided by the Company on the witness stand, but would review this adjustment in conjunction with a review of Research and Development and address her findings in this brief. (Tr. 1775-1796, 1800-1801) Upon review of the subject and additional information supplied by the Company, Staff Witness Bowers acknowledges that this proposed adjustment was, in fact, included in two areas and this proposed adjustment for Special Projects has been eliminated from the Staff proposed revenue requirement presented in Appendix A, because it is already reflected in the Research and Development adjustment discussed below.

ix. Research and Development Costs

Staff Witness Bowers disallowed research and development costs for projects that were not related to the provision of delivery services. The limited information provided by the Company indicated that the end result of the R & D would be a marketable product that has no delivery services characteristics. Some of the narrative even discussed the fact that the end result of some aspects of the R & D would be a Business/Marketing Plan. (ICC Staff Ex. 4.0, page 7)

x. Interest On Customer Deposits

Staff witness Jones proposed an adjustment to interest on customer deposits based on a change in the annual interest rate and on the correction of a Company error in the calculation of jurisdictional interest. (Staff Ex. 2.0, p. 5 and Schedule 2.2) While the Company accepts the correction of the error, it opposes the change in the interest rate on the grounds that it is a "type of adjustment that looks at only one cost item included in the test year."

Interest on customer deposits is simply one expense for which there is a known and measurable change; i.e., the interest rate adopted by the Commission on December 6, 2000, in Docket No. 00-0772. Known and measurable changes to a historical test year are standard practice, used by utilities and Commission Staff, seeking to more clearly reflect present and future conditions. In fact, the Company has included several such adjustments in its test year in this proceeding. It has proposed adjustments to reflect known and measurable changes for Distribution Plant facilities placed into service/sold in 2001, salary increases in 2001, discontinuance of the Light Bulb Program in 2001, and rate case expense. (Staff Ex. 16.0, p. 4)

Ms. Jones' adjustment to customer interest based on a known and measurable change in the annual interest rate is appropriate and should be accepted.

xi. Uncollectibles Expense

Staff witness Jones proposed an adjustment to uncollectible accounts, which is based on an historical 4-year average of uncollectibles as a percent of delivery services revenue. (Staff Ex. 2.0, p. 6 and Schedule 2.3) Ms. Jones maintains that her method, which incorporates several years' experience for total uncollectibles, yields a more normal level of delivery service revenue uncollectibles for ratemaking purposes than does the 1-year analysis of uncollectibles by customer class proposed by the Company.

The 4-year average used in Ms. Jones' adjustment was calculated by the Company, based on actual uncollectibles experience for the years 1996, 1997, 1998, and 2000, and was the uncollectibles factor included in its Gross Revenue Conversion Factor. (Staff Cross Ex. 69) The fact that the Company also proposes to use the same average to determine the uncollectible portion of incremental revenues confirms that it produces a reasonable result.

Ms. Jones' adjustment provides a more normal uncollectible expense level for the test year and should be accepted.

xii. Taxes Other Than Income Taxes

A. Use Tax[3]

Staff witness Jones proposed an adjustment to remove out-of-period state use tax of $1.401 million from test year 2000 operating expenses. (ICC Staff Ex. 2.0, p. 7-8, and Schedule 2.5) The tax liability resulted from a sales tax audit for the period October 1994 through December 1997. In his rebuttal and surrebuttal testimonies, ComEd witness Hill presented three reasons for including the tax in the test year. (ComEd Ex. 23.0, pp. 22-23, and ComEd Ex. 45.0, pp. 29-30)

ComEd witness Hill argues that the tax is a legitimate business expense imposed by Illinois tax law. Ms. Jones does not dispute this aspect of his argument. However, even a legitimate business expense should pertain to the test year. Staff's proposed adjustment does not disallow any use tax paid in the test year on purchases made in the test year. The adjustment disallows only use tax incurred in periods prior to the test year, specifically, October 1994 through December 1997.

ComEd witness Hill's second argument is that the use tax relating to capitalized plant and equipment would be in plant in service but for the Company's accounting policy, which is to account for tax audit adjustments as expense. Ms. Jones agrees. However, in Mr. Hill's surrebuttal he testifies that the majority of the additional use tax liability is related to plant and equipment that is included in rate base. (ComEd Ex. 45.0, p. 29) Apparently the Company had the knowledge with which to reclassify the use tax assessment for ratemaking purposes but chose not to do so or to provide the parties to this case with the information to do so.

[3] Addition to ALJ outline

Although ComEd witness Hill's third argument is that the Company is routinely subject to tax compliance audits resulting in either an increase or decrease in tax liabilities, he presents no evidence that the additional use tax liability recorded in 2000 for prior years represents a "normal level." On the contrary, he states in his surrebuttal testimony that these audits do not happen every year. (ComEd Ex. 45.0, p. 30) The Company filing, which supports this assertion, indicates that account 408.1, the sales and use tax expense account in which tax audit liabilities are recorded, had a YTD total balance of zero for 1999 and $15,278 for 1998, as compared to $3.8 million for 2000. This clearly indicates a disparity among years.

The evidence in this proceeding shows that the use tax expense in question does not reflect a normal, recurring expense that pertains to the test year. Therefore, Ms. Jones' adjustment to remove this out-of-period expense is just and reasonable and should be accepted.

B. Payroll[4]

Staff is proposing an adjustment to taxes other than income to account for payroll taxes that will change based upon adjustments to salaries and wages expense accepted by the Commission. For all three of Staff's proposed adjustment to salaries and wages expense, i.e. layoffs, incentive compensation, distribution, payroll taxes have been adjusted by 8%. The Company agrees that to the extent that these adjustments are accepted by the Commission, the payroll taxes do need to be similarly adjusted. (ComEd Ex. 23.0, p. 24, l. 529 – 535)

[4] Addition to ALJ outline

xiii. Incentive Compensation

Staff is proposing two adjustments, one to distribution salaries and wages expense and the other to administrative and general salaries and wages expense, for the incentive compensation expenditures dependent upon financial goals of the Company. Staff believes these specific goals primarily benefit shareholders and not ratepayers. While the Company still believes the incentive compensation component included in the Company's proposed revenue requirement to be reasonable and appropriate, it is not contesting Staff's proposed adjustment in order to narrow the issues in this proceeding. (ComEd Ex. 45.0, p. 38, l. 819 – 821)

xiv. Rate Case Expenses

xv. Outside Collection Agency Expense[5]

The Company allocated 100% of outside collection agency expense incurred in the test year to delivery services. Staff witness Jones proposed an adjustment to reduce this expense by $1.106 million, based on the ratio of DST revenue requirement to total 2000 revenue in the test year. (Staff Ex. 2.0, p. 7 and Schedule 2.4) Delivery services ratepayers should not bear the total expense for collecting unpaid bills, which include charges for the cost of generation, transmission and distribution services.

The Company does not object to Staff's proposed adjustment. (ComEd Ex. 23.0, p. 22) Ms. Jones' adjustment is reasonable and proper and should be accepted.

4. Prudence of Expenses

[5] Addition to ALJ outline

5. Other Revenue & Expense Issues

E. Cost of Capital

1. Capital Structure

The following witnesses provided testimony regarding the appropriate capital structure for setting delivery service rates in this proceeding: John Ebright, on behalf of ComEd, Janis Freetly, on behalf of Staff, and Steven Walter, on behalf of the City of Chicago.

ComEd witness John Ebright initially proposed a pro forma capital structure containing approximately 54% debt and 46% equity based on a year-end 2000 capital structure reflecting pro forma adjustments through December 31, 2002. (ComEd Ex. 11.0 at 3) Staff witness Janis Freetly recommended a March 31, 2001 capital structure consisting of approximately 60% debt and 40% equity. (Staff Ex. 19.0, Schedule 19.1) City witness Steven Walter initially recommended a capital structure of about 55% debt and 45% equity in direct testimony. (COC Exhibit 1.0, Attachment 6) However, in his rebuttal testimony, Mr. Walter recommended that the Commission adopt the capital structure proposed by Ms. Freetly. (COC Exhibit 2.0 at 7) Ultimately, ComEd, City and Staff agreed that ComEd's capital structure for use in this proceeding should be set at approximately 57% debt and 43% common equity, which Ms. Freetly presented in supplemental rebuttal testimony. (Staff Ex. 27.0, Schedule 27.1)

a. Known And Measurable Changes to Test Year Capital Structure

i. TFI Retirements in 2001 and 2002

The pro forma capital structure proposed by ComEd reflected pro forma adjustments to the balance and cost of long-term debt for forecasted retirements from January 2001 through December 31, 2002 of transitional funding instruments ("TFIs"). ComEd claimed that this pro forma adjustment was known and measurable as demonstrated by the prospectus issued in connection with the TFIs which delineates the amount of and timing of TFI retirements. (ComEd Ex. 28.0 at 2) ComEd also claimed that the retirement of the TFIs would not be accomplished through debt refinancing.

Staff witness Freetly originally recommended that the Commission reject ComEd's proposed pro forma adjustments to reflect the scheduled retirements of TFIs. (Staff Ex. 5.0 at 5) Staff did not agree with these pro forma adjustments because although the retirement dates are known, the manner in which such retirements are to be refinanced is not known. (Staff Ex. 19.0 at 2)

In his direct testimony, Mr. Walter reflected the retirement of the TFIs through the end of 2001, but excluded those for calendar year 2002 for being out of the test year. (COC Exhibit 1.0 at 15) Nevertheless, the City also agreed to the inclusion of the retirements of the TFIs through 2002 as put forward by Ms. Freetly in supplemental rebuttal testimony. (Tr. 2945-2946)

Although Staff does not agree with piecemeal pro forma adjustments to capital structure, because Staff has been satisfied that ComEd will be able to retire TFIs through 2002 with internally generated funds and to resolve the cost of capital issue in this proceeding, Staff has agreed to accept this adjustment. (Staff Ex. 27.0)

ii. Other

ComEd also proposed an adjustment to the balance of common equity to account for ComEd's corporate restructuring in January 2001. (ComEd Ex. 11.0, Schedule 11.5) Ms. Freetly's balance of common equity was measured as of March 31, 2001, thereby incorporating the effect of the corporate restructuring on ComEd's common equity balance. (Staff Ex. 5.0 at 9)

b. Purchase Accounting Adjustments

On October 20, 2000, Unicom and PECO merged and Exelon became the parent company of both entities and all of the respective subsidiaries. The merger was accounted for using the purchase method of accounting. The difference between the estimated fair market value and the carrying value of each long-term debt issue was recorded as an adjustment to the unamortized premium/discount balance. ComEd proposed to reflect these fair value adjustments in the balance of long-term debt. (ComEd Ex 28.0 at 5-6)

Staff witness Freetly opposed ComEd's proposal. (Staff Ex. 5.0 at 8) Since rates are set on the basis of original cost, fair value adjustments should not be included in the balance of long-term debt. Restating the unamortized premium/discount to fair value and attempting to pass those changes through to ratepayers results in passing costs associated with the merger to ratepayers. (Staff Ex. 19.0 at 7)

As part of the agreement presented by Ms. Freetly in supplemental rebuttal testimony, ComEd agreed to use the original cost unamortized premium/discount balances. (Staff Ex. 27.0; Tr. 2945-2946)

c. Note Receivable from Exelon

ComEd's balance of common equity included a $1.062 billion receivable from Exelon to cover its tax liability on the intangible transition charges that ComEd collects. ComEd expects Exelon to pay this non-interest bearing receivable over the years 2001 through 2008 in conjunction with the payment of the taxes resulting from the collection of the intangible transition charges. (ComEd Ex. 28.0 at 4-5) ComEd claimed that this transaction results in additional common equity for ComEd because ComEd does not have to pay the income taxes out of its own funds. (ComEd Ex. 52.0 at 5)

Staff witness Freetly did not include the $1.062 billion receivable in her recommended balance of common equity. ComEd will collect on the receivable each year as the income taxes come due. Ms. Freetly argued that this intercompany receivable will not result in a $1.062 billion increase in capital that can be invested. (Staff Ex. 19.0 at 3-5)

Although Staff does not agree with the underlying methodology, as part of the disposition of cost of capital issues, Staff agreed to include the amount of the receivable from Exelon for the year 2001. The final recommended balance of common equity was derived using a forecasted December 31, 2001 balance and adding $125 million to reflect the amount of the receivable for 2001. (Staff Ex. 27.0 at 2 and Schedule 27.2)

2. Cost of Debt

Although Staff does not agree with the underlying methodology, Staff urges the Commission to adopt a 6.95% cost of long-term debt for ComEd in this proceeding. This cost represents the embedded cost of long-term debt derived using the annual amortization and unamortized balances of debt discount and premium associated with the original cost and the retirements of the TFIs through 2002. (Staff Ex. 27.0) The

6.95% cost of long-term debt is part of the agreement amongst ComEd, City and Staff to resolve the cost of capital issue. (Tr. 2945-2946)

a. Purchase Accounting Adjustments

ComEd claimed that the cost of debt should be calculated based upon the fair value adjustments to the unamortized premium/discount balances. ComEd claimed that the adjustment to the carrying value of long-term debt has the effect of adjusting the cost of debt to the current market rates at the time of the merger. (ComEd Ex. 28.0 at 7)

Staff opposed this adjustment to fair value because the overall rate of return for ratemaking purposes should reflect the embedded cost of debt, which is based on the original, actual costs that the Company incurred on that debt. Restating carrying value to fair market value produces illogical debt costs and is inconsistent with original cost ratemaking. (Staff Ex. 5.0 at 8) ComEd agreed to use the original cost for calculating the embedded cost of long-term debt and further agreed to continue to track and record separately the unamortized balance and annual amortization of the original debt discount and premium. (Staff Ex. 27.0 at 2; Tr. 2945-2946)

b. Cost of Variable Rate Long-Term Debt

ComEd has four variable rate long-term debt issues, two pollution control obligations – Series 1994B and 1994C Illinois Development Finance Authority Pollution Control Revenue Refunding Bonds, and two Floating rate Senior Notes. In rebuttal testimony, Mr. Ebright stated that the actual rates as of August 31, 2001 should be used to update ComEd's interest rates on its variable rate long-term debt. (ComEd Ex. 28.0 at 8) Ms. Freetly accepted those interest rates and adjusted the annualized interest expense for the variable rate issues to reflect the updated interest rates. (Staff Ex. 19.0 at 9, Schedule 19.2)

3. Cost of Common Equity

Testimony regarding the appropriate cost of equity for ComEd was put forth by Daniel Thone on behalf of ComEd, Janis Freetly on behalf of the Staff, and Steven Walter on behalf of the City of Chicago. Sam Peltzman and Christopher Lee Culp also sponsored testimony on behalf of ComEd regarding the risk that ComEd faces in today's electricity markets. Alan Pregozen provided rebuttal testimony on behalf of the Staff regarding ComEd's proposed leverage adjustment and the risk level of ComEd's delivery service operations.

<u>ComEd</u>

Mr. Thone compiled two samples, a group of ten electric utilities and a group of eight gas utilities he considered comparable to ComEd because they derive most of their revenues from utility operations. Gas utilities were included due to their primary function as a delivery services provider, and because the gas industry has already moved toward deregulation. Mr. Thone's analysis utilized companies with Standard & Poor's ("S&P") credit ratings similar to ComEd. (ComEd Ex. 8.0 at 7)

Mr. Thone utilized three basic methodologies to estimate ComEd's cost of equity: the discounted cash flow model ("DCF"), the capital asset pricing model ("CAPM"), and the comparable earnings method. He used the Miller model to adjust his DCF estimates and the Hamada model to adjust his CAPM estimates.

The Miller model is a method for measuring the effect on the cost of equity due to changes in leverage in the capital structure based on the classic theory developed by

Modigliani and Miller. After Mr. Thone calculated his initial DCF estimates for each of the companies in his samples using the quarterly DCF model, he used the Miller model to calculate the implied unlevered cost of equity for his samples. He then re-levered the cost of equity using ComEd's proposed capital structure. (ComEd Ex. 8.0 at 10-12) Based on the DCF methodology with the Miller model adjustment as implemented by Mr. Thone, the required return for his electric sample weighted by market capitalization ranged from 11.41% to 14.99%, with a midpoint of 13.20%. The required return for his gas sample weighted by market capitalization ranged from 16.38% to 16.99%, with a midpoint of 16.68%. (ComEd Ex. 8.0 at 16)

The Hamada model modifies the beta component of the CAPM model to account for the effect of a company's financial leverage on its risk. Similar to his Miller model adjustment, Mr. Thone removed the effect of financial leverage from his sample companies' betas using market-value capital structures to obtain an unlevered beta and then re-levered it using the proposed capital structure of ComEd. He then used the re-levered betas for his sample companies when estimating the cost of equity with the CAPM methodology. (ComEd Ex. 8.0 at 10-12) Mr. Thone's CAPM model estimates for the electric sample ranged from 10.20% to 12.47% with a weighted average of 11.78%, and for the gas sample ranged from 12.36% to 14.01%, with a weighted average of 13.40%. (ComEd Ex. 8.0 at 21)

For the comparable earnings method, Mr. Thone used *Value Line* estimates of return on equity for the years 2003 through 2005 for the companies in his samples to estimate ComEd's cost of equity. He weighted the *Value Line* estimates by market capitalization to obtain a weighted average estimate for his electric and gas samples.

The market-weighted average *Value Line* expected return on equity was 14.13% for his electric sample and 13.37% for his gas sample. (ComEd Ex. 8.0 at 21-22)

Mr. Thone then summarized the results by averaging the weighted average estimates derived by the DCF and CAPM methods and the Value Line return on equity projections for his electric and gas samples. He then weighted the electric and gas sample estimates by the market capitalization of the underlying companies. Mr. Thone concluded that ComEd's cost of equity is at least 13.25%. (ComEd Ex. 8.0 at 23-24)

Staff

Since ComEd's common stock is not market-traded, Ms. Freetly also utilized comparable samples to estimate the cost of equity for ComEd. She used a sample of integrated electric utility companies and a sample of gas distribution companies. Ms. Freetly selected an electric sample based on the following criteria. In her electric sample she began with domestic publicly traded companies classified as electric utilities within *S&P Utility Compustat* with 75% or more revenue derived from electric operations based on 2000 data. She then removed any company that had an S&P debt rating other than A, A-, or BBB+. Next, she eliminated companies without long-term growth rates from neither Zacks Investment Research ("Zacks") nor Institutional Brokers Estimate System ("IBES"), companies involved in pending significant mergers or acquisitions, and companies without Value Line beta estimates. Ms. Freetly chose the companies in her gas sample in a similar fashion. The selection criteria began with all domestic publicly traded companies classified as gas utilities within *S&P Utility Compustat* with 75% or more revenue from gas services. Companies with S&P debt rating outside the range of A+ through BBB were eliminated along with those that had neither Zacks nor IBES long-term growth rates. Companies involved in pending significant mergers or acquisitions were eliminated next, along with Southern Union because it does not pay dividends. (Staff Ex. 5.0 at 13-14)

Ms. Freetly measured the investor-required rate of return on common equity for ComEd with the DCF and risk premium models. She implemented a constant-growth quarterly DCF model on each of the companies in her electric and gas samples. To measure market-consensus expected growth, she averaged IBES and Zacks growth rate estimates. (Staff Ex. 5.0 at 16-18) Ms. Freetly measured each company's current stock price with its closing market price from August 10, 2001. (Staff Ex. 5.0 at 18) Ms. Freetly's revised DCF analysis produced return on common equity estimates of 13.34% for her electric sample and 11.97% for her gas sample. (Staff Ex. 12.0, Schedule 12.4)

Ms. Freetly also utilized the Capital Asset Pricing Model ("CAPM"), a one-factor risk premium model. She used the current yield on thirty-year U.S. Treasury bonds as a proxy for the risk-free rate since long-term expectations for inflation and real Gross Domestic Product growth greatly exceed the current Treasury bill yield. (Staff Ex. 5.0 at 26) The expected rate of return on the market was estimated by conducting a DCF analysis on the firms composing the S&P 500 Index as of the second quarter of 2001, which equaled 15.31%. (Staff Ex. 5.0 at 27) Ms. Freetly used Value Line's beta estimates for the companies in her samples. (Staff Ex. 5.0 at 28) Her risk premium model estimated a required return on common equity of 10.94% for the electric sample and 11.06% for the gas sample. (Staff Ex. 5.0 at 30)

Based on her analysis and informed judgment, Ms. Freetly concluded that the investor-required rate of return on common equity for ComEd equals 11.72%. The average investor-required rate of return on common equity for the electric sample, 12.14%, is based on the average of the revised DCF-derived results (13.34%) and the risk premium-derived results (10.94%). The average investor-required rate of return on common equity for the gas sample, 11.52%, is based on the average of the revised DCF-derived results (11.97%) and the risk premium-derived results (11.06%). Ms. Freetly then applied one-third weight to the electric sample average investor-required rate of return on common equity, and two-thirds weight to the gas sample average investor-required rate of return on common equity since S&P credit ratings, S&P business position scores, and common equity ratios indicate that ComEd is closer in risk to the latter than to the former. (Staff Ex. 12.0 at 2)

City

In his direct testimony, City witness Walter removed Mr. Thone's sample of gas utilities because they are in a different industry. He also removed four companies from the electric utility sample that have S&P ratings lower than ComEd, and thereby have inherently greater risk. (COC 1.0 at 4)

City witness Walter used the DCF estimates that Mr. Thone calculated for some of the electric utilities in his electric sample. He did not include the leverage adjustment that Mr. Thone implemented. He excluded the comparable earnings approach that Mr. Thone presented which relied on Value Line return on equity projections. He relied on the CAPM estimates presented by Mr. Thone for his limited electric sample companies. (COC 1.0 at 4-5) His cost of equity recommendation equaled 11.93%. (COC 1.0 at 3)

The evidence demonstrates that the cost of common equity recommendation of Ms. Freetly is reasonable and should be adopted by the Commission for determining

ComEd's electric delivery service rates. She utilized theoretically valid models and implemented them using appropriate estimates of investor expectations of growth, beta, and the risk-free rate. As part of the resolution of the cost of capital issue, ComEd and the City accepted her 11.72% cost of equity estimate. (Tr. 2945-2946)

a. Comparable Groups

In his rebuttal testimony, Mr. Thone criticized Ms. Freetly's sample. He claimed that his sample groups were superior to those used by Ms. Freetly because he focused on companies whose primary business is distribution. (ComEd Ex. 27.0 at 6-7)

In her rebuttal testimony, Ms. Freetly pointed out that the criteria used by Mr. Thone did not necessarily limit his samples to utilities primarily engaged in distribution. She further pointed out that the criteria that she relied on to select the electric and gas utilities that comprised her samples were more stringent than those employed by Mr. Thone. When the criteria she utilized were applied to Mr. Thone's samples, several companies did not make the cut. (Staff Ex. 19.0 at 11-12)

b. Methodological Issues

Ms. Freetly testified that Mr. Thone's leverage adjustments are seriously flawed and do not accurately reflect the effect on the cost of equity from differing degrees of financial leverage. (Staff Ex. 5.0 at 33) The models that Mr. Thone used fail to reflect the significance a company's cost of debt has on financial leverage. (Staff Ex. 5.0 at 35-37) Mr. Thone used the <u>market value</u> capital structures of the sample companies to unlever the cost of equity estimates, but when relevering, he wrongly used ComEd's proposed <u>book value</u> capital structure. Market value should be used when implementing the Miller and Hamada models for both unlevering and relevering. (Staff

Ex. 5.0 at 37-40) Mr. Thone also wrongly excluded short-term debt in the market-based capital structure ratios that he used to unlever the companies in his samples, which understates the amount of leverage they carry. (Staff Ex. 19.0 at 12-13) Further, ComEd treated the TFNs as regular debt when executing his leverage adjustments, which causes the models to overstate the effect of financial leverage from TFNs on the cost of equity. (Staff Ex. 5.0 at 40-41) Finally, Ms. Freetly argued that these leverage adjustments are not suitable for estimating a particular cost of equity. The Commission reached a similar conclusion in Docket Nos. 99-0120/99-0134 Consol. and Ms. Freetly urged the Commission to do so here. (Staff Ex. 5.0 at 41-42)

Mr. Pregozen submitted rebuttal testimony stating that the simplistic assumptions embodied in the ComEd Miller and Hamada models lead to inaccurate estimates of the impact of debt leverage on the cost of common equity. (Staff Ex. 26 at 2) Since the risk-free rate is lower than the cost of risky corporate debt, the ComEd Miller and Hamada models produce upwardly biased cost of common equity estimates for financially leveraged firms. (Staff Ex. 26 at 3) He opposed using the ComEd Miller and Hamada models for the purpose of setting utility's cost of capital or any component thereof, including capital structure, because the predictions of those models vary greatly from reality. (Staff Ex. 26 at 6)

Ms. Freetly also rejected Mr. Thone's use of the comparable earnings methodology because the expected returns on book value are not appropriate estimates for required returns. (Staff Ex. 5.0 at 42-43) She noted that the Commission rejected use of the comparable earnings methodology consistently in Docket Nos. 99-0121, 89-0033, and 92-0448/93-0239 Consol. (Staff Ex. 5.0 at 43)

Mr. Thone testified that weighted averages are more representative of a portfolio. Ms. Freetly disagreed and pointed out that the objective in using a sample to measure the cost of common equity for a single company is the reduction in measurement error. There is no necessary relationship between the size of a company and the reduction of measurement error. The companies comprising a sample should be weighted differently only if there is reason to believe that some of the companies are closer in risk to the subject company than others. Under this approach, companies would be weighted on the basis of closeness in risk, not size. (Staff Ex. 19.0 at 16)

c. Market Versus Book Issues

Mr. Thone adjusted his market-based DCF and CAPM models for application to book value through his implementation of the Miller and Hamada models, claiming that applying market returns to book values will under-fund the necessary returns when book values are less than market values. (ComEd Ex. 8.0 at 22-23; ComEd Ex. 27.0 at 15) Ms. Freetly countered that these adjustments have both theoretical and empirical flaws as they are based on the incorrect notion that utilities should be authorized rates of return in excess of the investor-required return whenever their market values exceed book values. If applying a market-based rate of return to a book value rate base provided a return that did not meet investor requirements, market prices would fall toward book value. Yet, a market to book adjustment was not necessary for achieving current market to book values, therefore, it cannot be necessary to support those values. The Commission has previously rejected this false notion and should do so here. (Staff Ex. 5.0 at 36-37; Staff Ex. 19.0 at 17-18)

4. Overall Rate of Return

Staff witness Freetly's supplemental rebuttal testimony presents a compromise position regarding the weighted average cost of capital. (Staff Ex. 27.0) ComEd and the City stated their agreement with Ms. Freetly's position and accepted a weighted average cost of capital of 8.99%. (Tr. 2945-2946) This cost of capital is based on a pro forma December 31, 2001 capital structure. Although Staff does not agree with all the underlying methodologies used to estimate that pro forma capital structure, Staff agrees that the December 31, 2001 capital structure fairly represents the proportion of debt and equity that will be outstanding during the period that rates will be in effect. The Commission should adopt the following balances and costs, to which ComEd, the City and Staff agreed:

Component	Balance	Percent of Total Capital	Cost	Weighted Cost
Long-term Debt	$6,965,641,050	57.14%	6.95%	3.97%
Common Equity	$5,224,000,000	42.86%	11.72%	5.02%
Total Capital	$12,189,641,050	100.00%		
Weighted Average Cost of Capital				**8.99%**

F. Cost Of Service and Rate Design

1. Cost of Service Study Issues

a. Marginal Cost Study

The record in this proceeding underscores the wisdom of basing all facets of delivery services ratemaking on embedded costs. While ComEd has strenuously supported a marginal cost standard, the record clearly finds embedded costs to be a superior alternative. This enables the Commission to make an easy decision. Having already accepted embedded costs for the delivery services rates of ComEd and all other Illinois utilities, the Commission should reaffirm those decisions in this case as well.

ComEd proposes using marginal costs for two purposes: (1) as a foundation for the design of delivery services rates and (2) to set unbundled service credits. Both proposals are clearly inappropriate and should be rejected in favor of embedded costs.

The Company's proposal to base delivery services rates on marginal costs is clearly deficient.

ComEd proposes that delivery services rates be based on the marginal cost prepared by witnesses Alongi and Kelly. However, the results of the study cannot be directly used because ComEd's calculation of marginal costs exceeds the proposed revenue requirement by approximately 25% (ComEd Ex. 13.1, p. 3 of 48). Therefore, the Company prorated these marginal costs downwards using the Equal Percentage of Marginal Cost (EPMC) approach to serve as the foundation for ComEd's proposed delivery services rates.

This marginal cost proposal falls short on two fronts. First, problems arise in applying the theory of marginal costs to the calculation of marginal costs for ComEd.

Second, fitting these marginal cost calculations to the revenue requirement developed on the basis of embedded costs presents problems as well.

The Company justifies marginal costs on the basis of economic efficiency. The Company's witnesses on the issue, Drs. Gordon and Makholm, repeatedly argue that marginal cost-based pricing produces more efficient results than the embedded cost alternative. However, a wealth of evidence finds their arguments to be lacking. Their claim of economic efficiency rests on the faulty premise that conclusions concerning marginal costs in the artificial world of perfect competition must necessarily apply to real world markets. However, the real world is considerably more complex and far from perfect. These differences not only make it considerably more difficult to determine marginal costs but they also undermine the value of marginal costs as a measure of efficiency (ICC Staff Ex. 7.0, p. 4).

There is no consistent set of principles for calculating marginal costs.

Marginal costs are easily identified under perfect competition because they equal the market-clearing price. However, a market-clearing price does not exist for a real world utility providing delivery services in a monopoly market. Therefore, the marginal costs of delivery services need to be calculated (ICC Staff Ex. 7.0, p. 5).

For a capital-intensive utility, there is no obvious way to calculate marginal costs and a variety of methods may be used. ComEd's filing provides a case in point because the Company itself sponsors two widely varying calculations of marginal costs. For delivery services rates, the Company calculates a set of marginal costs that exceed embedded costs. However, the Company's avoided cost calculation of unbundled metering and billing falls far below embedded costs. The only common thread between these two calculations is ComEd's claim that both rest upon marginal cost principles. (ICC Staff Ex. 21.0, p. 20)

For example, the Company filing includes two different and contradictory calculations of the marginal cost of residential meters. One calculation for delivery service rate design produces an average monthly cost of $2.09 for each of the 2,057,590 standard meter installations for Single Family Non-Space Heating customers (ICC Staff Ex. 21.0, p. 21). For those same customers ComEd calculates an avoided marginal meter cost of only 15 cents per month (ComEd Ex. 13.0, Attachment P).

This example demonstrates that the marginal cost standard referenced by Dr. Makholm does not exist. The level of marginal costs is whatever the practitioner wants it to be. If ComEd wants to produce a low marginal cost, it uses an avoided cost standard. To calculate a higher number it only needs to throw some capital costs into the calculation. (ICC Staff Ex. 21.0, p. 21)

The marginal cost study presented by ComEd in this proceeding is deeply flawed.

There were two methods proposed for allocating revenue requirement to each delivery rate class in this docket: a marginal cost of service study ("COSS") proposed by Edison and supported by the U.S. DOE, and an embedded COSS also developed by Edison as an alternative to the marginal COSS. Staff supports the embedded COSS model, with some adjustment. Edison's marginal COSS was discussed in the Panel Testimony of Lawrence S. Alongi and Sharon M. Kelly, P.E. (ComEd Ex. 13.0, 32.0 and

50.0) Edison promoted the use of the marginal COSS through the testimony of Kenneth Gordon (ComEd Ex. 2.0, 21.0 and 44.0) and Jeff D. Makholm (ComEd Ex. 15.0, 34.0 and 55.0) Edison's alternative COSS, which was developed on an embedded basis, was discussed in the testimony of Alan C. Heintz. (ComEd Ex. 14.0, 33.0 and 57.0) Staff supported the embedded COSS, with adjustments, as discussed in the testimony of Mike Luth (ICC Staff Ex. 6.0 and 20.0) and Peter Lazare. (ICC Staff Ex. 7.0 and 21.0)

One of the central tenets in Edison's support for a marginal COSS to allocate delivery services costs is the concept that "Cost causer pays." Edison's position is that only the marginal COSS reflects the concept of cost causation, while the embedded COSS does not. Edison believes that a marginal COSS is forward-looking, while the historical basis reflected in an embedded COSS has little to do with cost causation.

Staff supports an embedded COSS because it reflects the accumulation of actual costs to serve customers, rather than an estimate of costs to serve an unknown level of future growth in the use of the distribution system, and is therefore a better representation of cost causation pertaining to the costs at issue in this docket. Edison's filing contradicts the idea that marginal costs from growth in the use of the distribution system, particularly by existing customers, are measurable because a higher revenue requirement did not result from weather normalization. Weather normalization increased billing units, reflecting increased use of the distribution system by existing test year customers, yet did not result in increased cost of service.

There is a disconnect between what is measured in a marginal COSS and the historical delivery services revenue requirement that is to be recovered through the rates established in this docket. The purpose of the marginal COSS is to determine the incremental costs that the Company incurs to provide delivery services to its various customer classes. (ComEd Ex. 13.0, p. 8, l. 172-174) The Panel Testimony of Edison witnesses Alongi and Kelly further describes the marginal COSS by stating that "it only reflects the marginal costs associated with adding customers and load to the delivery system." (Id., l. 177 and 178) Thus, Edison's marginal COSS reflects the current costs of installing delivery services equipment and connecting new delivery customers, but the equipment to serve existing customers is already in place, and the costs are already established. The equipment is not due to be replaced overnight when the new delivery services rates are placed into effect, so the idea that rates should be based upon the relative costs to replace equipment already in place is not logical. The embedded COSS approach of basing rates upon the use of current equipment at the cost of providing that equipment, when it was provided, is more appropriate.

For example, Edison's workpapers indicate that the cost of an overhead distribution line installed in 1973 for $1 million and still in use is estimated to cost $4 million if installed today. (ComEd Ex. 13.2, p. 4, l. 45, the year 1973 = 100) An embedded COSS would allocate the $1 million cost of the use of the line by an allocation factor such as non-coincident peak. A marginal COSS distorts the cost of service because the replacement cost of $4 million would be used to allocate the cost of the $1 million overhead distribution line. The users of the overhead distribution line did not cause $4 million in costs; they caused $1 million in costs. While $4 million may represent what it would cost to install the line today, the line is not being installed today; it was installed in 1973. To the extent that $4 million is considered to be forward-looking, there is no consideration given to the remaining use of the $1 million line. The line could be used for another 10 years or more, which would mean that rates based upon $4 million in replacement costs are irrelevant to the $1 million in costs to serve customers using the line today and for the next 10 years. Since the users of the $1 million overhead distribution line have not caused $4 million in costs, the rates paid by those users should not be based upon their having caused $4 million in costs.

Another economic assumption used by Edison to promote the marginal COSS is that the marginal COSS sends price signals to customers for their use of the distribution system, resulting in efficient choices in the use of equipment by those customers. Since the marginal COSS is based upon the replacement cost of equipment already in place, the only price signal that the marginal COSS can be interpreted to send is the cost to serve new customers. Edison's marginal COSS shows some widely varying costs of providing service to a new customer within each rate class, depending upon the density of electricity distributed in the region where the new customer is to be located. For example, the Residential Single Family No Space Heat class, which is the class with the highest level of marginal costs in Edison's marginal COSS, (ComEd Ex. 13.1, p. 3) coincident peak related distribution investment cost ranges from $381 to $1,355 per kW, depending upon the density of the customer's location in the distribution system. (Id., p. 12) Dividing $1,355 by $381 results in a quotient of more than 3.5, which means that customers in the most expensive distribution density locations have an estimate of current equipment costs that average more than 3.5 times higher than new customers in the least expensive distribution density areas. For the highest marginal cost non-residential class, which is the 100-400 kW class, the range is $280 to $758 per kW, which is a quotient of 2.7, or nearly triple the costs of similar customers located in different distribution density areas.

Edison's proposed rates do not send price signals based upon the distribution density of the new customer's location. Proposed rates for existing customers in a given rate class are the same as those for potential new customers in the same rate class. Staff supports the concept of uniform rates within a given rate class, but the price signals sent by Edison's marginal COSS are irrelevant to the delivery services rates proposed in this docket for current customers.

Since Edison's marginal COSS does not measure the costs caused by existing customers to provide delivery services, and since the price signals provided by Edison's marginal COSS are irrelevant to the rates proposed in this docket, it is appropriate for the Commission to re-affirm its appropriate decision in the previous Edison delivery services Order to base rates upon an embedded COSS.

ComEd creates further distortions in adjusting its marginal cost study to the revenue requirement.

The use of the EPMC approach further distorts the results of ComEd's marginal cost study. By moving all rates away from their respective marginal costs, the EPMC ensures that no rate element will actually reflect its associated marginal cost (Staff Ex. 7.0, p. 6). In the current proceeding, ComEd's calculation of marginal costs exceeds its proposed revenue requirement by 25% which means that ComEd must prorate its marginal costs downward on an across-the-board basis by approximately 20% under the EPMC approach. This adjustment represents a further distortion to the marginal costs calculated by ComEd. As a result of this process it becomes unclear what relationship, if any, the adjusted marginal costs have to their respective rate elements (Staff Ex. 7.0, p. 6).

ComEd's proposal to use marginal costs conflicts with Commission precedent.

Since the initial delivery services cases filed in 1999, the Commission has consistently expressed its support for basing delivery services ratemaking on embedded costs, rather than marginal costs. For example, in ComEd's previous delivery services case (Docket No. 99-0117), the Commission consciously accepted embedded costs over marginal costs, stating as follows:

> In theory, marginal cost pricing promotes efficient competition because it sends efficient "price signals" to potential competitors. Edison repeatedly argues this point. The problem with this theory, however, is that in a regulated environment that is in transition, it also unduly protects an incumbent from competition. These "accurate price signals" that marginal cost pricing sends to competitors also promote inefficiencies in the incumbent utility. The Commission is of the opinion that while an efficient price signal to a potential competitor is a good thing, there must also be a symmetric price signal to the incumbent. This price signal to the utility is an incentive to provide good service and keep its customers. Embedded costs provide the best measure of a utility's ability to compete with alternate providers. The Commission refuses to accept the argument that price signals travel in only one direction. Order, p. 57.

ComEd's acceptance of an embedded cost revenue allocation represents a significant inconsistency.

ComEd indicates that it would accept, but not necessarily support, an allocation of the revenue requirement on the basis of embedded costs. This amounts to a significant inconsistency on the part of ComEd. The Company has argued strenuously in this case to use marginal costs in all aspects of delivery services ratemaking. For

ComEd to willingly discard that standard in favor of embedded costs to allocate the revenue requirement among rate classes calls into question the ratemaking "principles" on which its ratemaking is based (ICC Staff Ex. 7.0, p. 7).

b. Embedded Cost Study

Embedded costs provide a more reasonable foundation for delivery services ratemaking.

Embedded costs offer significant advantages over marginal costs. First, they are easier to determine. Marginal costs need to be created using numerous assumptions, statistical analyses and complex arguments that are all subject to error and distortion. Embedded costs, on the other hand, already exist as the actual accounting figures relied on by the Company. As a result, embedded costs avoid the estimation errors associated with marginal costs. (ICC Staff Ex. 7.0, p. 9)

Embedded cost calculations reflect a more consistent set of ratemaking principles than marginal costs. Whereas marginal cost calculations may or may not include capital costs depending on the situation, the embedded cost approach takes into account all relevant costs, fixed and variable, in each calculation. (ICC Staff Ex. 21.0, pp. 21-22).

ComEd's criticisms of embedded costs are unwarranted.

Company witness Makholm contends that embedded costs are backward looking. However, the track record based on embedded costs provides a framework for evaluating the future performance of utilities. Those utilities that have operated more efficiently in the past may be most capable of doing so in the future. Conversely, the utilities that have been beset by high costs may find it most difficult to compete in the future. (ICC Staff Ex. 7.0, p. 9).

Dr. Makholm goes on to claim that sunk costs are irrelevant when making forward-looking decisions (ComEd Ex. 34.0, p. 8). This statement is belied by ComEd's considerable efforts in this case to ensure that all costs including sunk costs are factored into delivery services rates. Only if ComEd were willing to base delivery services rates on avoided costs would Staff accept Dr. Makholm's argument that sunk costs are irrelevant. Until then, Staff will agree with ComEd that sunk costs matter a great deal. (ICC Staff Ex. 21.0, pp. 23-24).

Staff adjustment to Edison witness Heintz's COSS

Staff adjusted the embedded COSS prepared by Edison witness Heintz by eliminating the distribution loss factor from total kWh used to allocate the Illinois Electricity Distribution Tax and System Black Start costs. (ICC Staff Ex. 6.0, p. 10, l. 189-198) Staff made this adjustment because the tax is not based upon loss factor-adjusted kWh billing units. Staff also classified these costs as demand-related costs, rather than splitting between customer-related and demand-related costs, because the costs are based upon the use of the distribution system, rather than connections to the distribution system. (Id., p. 10, l. 199 through p. 11, l. 205) Edison accepted these adjustments through the testimony of Mr. Heintz. (ComEd Ex. 33.0, p. 1, l. 15 through p. 2, l. 28)

2. Interclass Revenue Allocation

G. Rate Design

1. RCDS Rate Design

a. Demand Ratchet

Edison proposed the use of a 12-month, peak period demand ratchet for the purposes of rate design for non-residential delivery services customers that are billed on a demand charge basis. (ComEd Ex. 12.0, p. 13, l. 308 through p. 19, l. 430) Under Edison's proposed ratchet, a delivery services customer would be billed according to the customer's peak demand in the month of that peak demand, and for the same level of demand for the next 11 months, whether or not the customer had required that demand in succeeding months. Edison's proposed demand ratchet was rejected in the Commission's Order in the previous Edison delivery services docket. (Order, Docket No. 99-0117, p. 64) Edison proposed the demand billing ratchet in order to balance out the costs of equipment built to serve a customer's peak demand with the charges that customer pays throughout the year. (Id., p. 16, l. 362 through l. 369)

Staff witness Luth opposed the use of a demand ratchet, and instead proposed billing upon the basis of the monthly peak demand of a delivery services customer. (ICC Staff Ex. 6.0, p. 14, l. 264 and 265, and l. 274 through 276) Mr. Luth indicated that while there may be some theoretical support for partially billing according to a demand ratchet, in practice, implementing a demand ratchet suffers from a lack of responsiveness to reduced electricity demand patterns (Id., p. 15, l. 285 through l. 299) Mr. Luth also indicated that a demand ratchet based upon a customer's non-coincident peak for 12 months does not recognize for billing purposes the delivery services costs that are affected by coincident peak use of the distribution system as a whole, rather than the non-coincident peak of individual customers. (Id., p. 17, l. 329 through l. 341) Given these shortcomings in Edison's proposal for a 100%, 12-month demand ratchet, Staff recommends that monthly demand readings be used to bill for delivery services.

Staff observes that a 12-month demand ratchet is quite responsive to increases in electricity delivery demand, but less responsive to a reduction in demand (Id., p. 15, l. 288-299). An increase in demand would result in an increase in ratcheted billed demand for that month and for the next 12 months, but a decrease in demand would not result in a decrease in ratcheted billed demand until the expiration of the 12-month period from the time of ratcheted peak billed demand. Under a demand ratchet, customers would have no control over their delivery services billing for up to 12 months, even if slumped business conditions or improved efficiency resulted in considerably lower electricity demand.

Edison Panel witnesses Clair and Crumrine replied that the economic incentive to install efficiency improvements or demand management programs would be improved by the use of ratcheted delivery services billings. (ComEd Ex. 31.0, p. 11, l. 248-256) There is no support for this claim provided in their testimony, other than a statement that "the economics may not be sufficient to warrant the installation of such programs, devices, or facilities." (Id., p. 11, l. 251 and 252) This statement does not explain how a demand ratchet would improve the economics of energy efficiency or management improvements over an unratcheted demand billing. Staff witness Luth provided an example of how a non-summer peaking customer could improve the reliability of the distribution system by installing energy efficiency or management measures which would improve non-peak demand, but could not improve peak demand. (Staff Ex. 20.0, p. 11, l. 226-236) The efficiency improvements would improve the reliability of elements of the distribution system planned around coincident peak demand occurring in the summer, but Edison's 100%, 12-month demand ratchet would not recognize those improvements in the form of a lower bill for delivery services. As a result, the customer might not make the improvements, which would be a loss to the distribution system during summer months, when the risk of outage from distribution system overload is greater.

Edison also supported an analogy to a real estate lease provided by DOE witness Swan concerning a demand ratchet. (ComEd Ex. 31.0, p. 10, l. 228 through p. 11, l. 247) Edison Panel witnesses Clair and Crumrine explained that the terms of a real estate lease do not change even if a change in business conditions results in the tenant not requiring the amount of space included in the lease. While that may be the case with a business real estate lease, another analogy might be the use of a gasoline service station to top off a delivery truck's gasoline tank. If the delivery truck takes only 15 gallons today, the cost of the gasoline today is not based upon the 100 gallons that may have been taken six months ago.

If the billing for the gasoline was changed so that it would be based upon the peak 100 gallons taken six months ago, the customer would have difficulty understanding the change in the method of billing. Similarly, the Company's 100%, 12-month demand ratchet represents a difference in the method of billing for delivery services currently in effect, and a difference in the method of billing for bundled, energy-included electric service. In rejecting Edison's proposal for a demand ratchet in the previous delivery services docket, the Commission stated that demand ratchets had not been favorably received for more than 15 years. (Order, Docket No. 99-0117, p. 64) Similarly, a change in the method of billing for delivery services would result in difficulty for a customer in comparing between either present delivery services rates or bundled rates, and Edison's proposed demand ratchet. That difficulty in comparability would most likely result in an unfavorable response to a demand ratchet by potential delivery services customers, and should continue to be unfavorably received by the Commission in this docket. The Commission should maintain monthly demand billing for delivery services instead of Edison's proposed 12-month, 100% demand ratchet.

i. General Service Ratchet

ii. Special Ratchet for Standby Customers

b. Definition Of Billing Demand In Rate RCDS

c. Impact on CTCs

d. Generation Facilities Under Rate RCDS

i. Proposals for Production Credit

ii. Proposals for Production Adder

2. Rate HVDS

Edison proposed Rider HVDS, which would be a credit per kW of demand applied to customers who take delivery services at 69 kV or above. (ComEd Ex. 12.0, p. 32, l. 734 through p. 33, l. 759) Rider HVDS would replace Rider 11 for delivery services customers, although Rider 11 would remain in effect for bundled customers. The current Rider 11 applies to both bundled and delivery services customers, and serves the same purpose as the proposed Rider HVDS, which is to recognize the cost differences between serving customers at 69 kV and above by providing a credit per unit of demand billed to those customers. Edison's proposed Rider HVDS is a considerably greater credit, however, at $1.69 per kW of demand (ComEd Ex. 50.0, Attachment C, p.s 2 and 3, column (G)) compared to 10.138 cents per kW under Rider 11. Edison's proposed Rider HVDS, calculated using its marginal COSS with rates designed under Edison's proposed 100%, 12-month demand ratchet, is more than 15 times the current high-voltage credit. The net amount that high-voltage customers would pay under Edison's proposed distribution facilities charge ranges from 89 cents to $2.03 per kW of demand,[6] depending upon the customer's delivery services rate class. This compares to the distribution facilities charge to be paid by non-high-voltage delivery services customers, as proposed by Edison, which would range from $2.58 to $3.72 per kW (Id.).[7]

Staff witness Luth agreed with the concept of reduced rates for high-voltage customers, but proposed a high-voltage rate, rather than a credit. Staff's proposed high-voltage rate is calculated using an embedded COSS, unratcheted demand billing units, and Staff's proposed revenue requirement. (ICC Staff Ex. 6.0, p. 11, l. 206 through p. 13, l. 247) Mr. Luth explained that a single high-voltage rate was simpler for a customer than having a standard class distribution facilities charge reduced by the HVDS credit.

[6] For customers currently receiving service at 69kV and above.

[7] For customers currently receiving service at 69kV and above.

The Company objected to Mr. Luth's proposal for a high-voltage rate for each demand-metered delivery services class, and instead prefers to maintain a credit applied to the standard class delivery services charge. The Company stated that a single high-voltage rate would increase the number of delivery services customer categories, and increase data processing complexity and costs. (ComEd Ex. 31.0, p. 25, l. 569 through p. 26, l. 589; and ComEd Ex. 49.0, p. 3, l. 65 through p. 4, l. 4, l. 75) Staff will not push for a high-voltage rate for each demand-metered delivery services rate class, and can recommend a uniform HVDS credit. Based upon allocation factors available prior to the Company's filing of surrebuttal testimony, Staff would recommend a uniform HVDS credit of $3.06039 per kW, but the uniform HVDS credit would need to be adjusted to account for the loss of Edison's largest customer who qualifies for the HVDS credit (ComEd Ex. 50.0, p. 10, l. 181 through 193). The loss of that customer, from peak demand of 269.5 mW down to less than 3 mW, reduced Edison's proposed HVDS credit by more than 36%. A similar reduction in the HVDS credit developed from Staff's pre-filed COSS would result in the credit being $1.95172 per kW.

The uniform HVDS credit would be based upon the difference between the standard distribution facilities charge and the High-voltage rate for each demand-metered delivery services rate class, weighted by the high-voltage demand billing units applicable to each delivery services rate class. Staff's HVDS credit is calculated according to an embedded COSS, unratcheted demand billing units, and Staff's revenue requirement, consistent with the design of all other Staff recommended delivery services rates.

The HVDS credit proposed by Edison, and the HVDS credit proposed by Staff, are both substantial. The credits represent well over one-third of the proposed standard delivery services rate for the demand-metered delivery services customer classes where the credit would be available. The current 10.138 cents credit is considerably less than one-third of the delivery services rate for demand-metered customer classes. Several parties to this docket would be affected by an increase in the HVDS credit. Some parties would enjoy considerably lower delivery services rates, others would incur significantly increased delivery services rates because customers not qualifying for the credit would be required to cover the class revenue requirement not paid as a result of the increased credit. The Company has explained that an increased delivery services rate will result in a reduced Customer Transition Charge ("CTC"), but the reduction in the CTC is capped to the amount that the CTC becomes zero. There is not necessarily a dollar-for-dollar trade-off between increased delivery services rates and a reduced CTC.

The increase in the standard distribution facilities charge can also be considered to have an anti-competitive effect upon the development of an active, vibrant energy market. An increase in delivery services rates, not offset by a corresponding decrease in the CTC below zero, narrows the margin for prospective ARES to competitively sell energy compared to bundled rates at an acceptable profit. A narrowed margin reduces the incentive for a prospective ARES to enter the Edison service area, dampening the power market if the incentive is too weak for the ARES to offer service. With only 43 customers potentially qualifying for the HVDS credit, the ARES market would be impacted by the increase in the credit if potential delivery services customers could not be expected to leave bundled services if those customers did not qualify for the credit.

The competing goal in determining whether the HVDS credit should be increased by a factor exceeding a multiple of 15 is deciding whether delivery services rates would be adequately cost-based if the credit is not increased to the levels indicated by the COSS, whether the COSS is developed on an embedded basis or on a marginal basis. A smaller HVDS credit would reduce the rate that delivery services customers who do not qualify for the credit would pay, but a smaller credit would also result in high-voltage customers paying more than the amount that the COSS indicates that high-voltage customers should pay. On the other hand, a lower delivery services rate for customers not qualifying for the HVDS credit might open the ARES market to those customers. The decision concerning the appropriate HVDS credit is therefore centered around the goal of possibly encouraging the development of the ARES market through delivery services rates that are lower for a larger number of potential customers, competing with the goal of establishing cost-based delivery services rates.

a. Eligibility

b. Calculation of Credit

c. Allocation of Costs to Other Classes

d. Exemption From Rate RCDS Facility Charges

e. Adoption Prior to Bundled Rate Tariff Change

3. Rider ISS

a. Pricing

For residential delivery service customers, ComEd proposes to use a formula that includes a market value energy charge (MVEC) applicable for the summer or nonsummer and peak or off- peak time periods. Collectively, these are the Time-of-Use (TOU) Interim Supply Energy Charges (ISEC). Transmission and Ancillary Transmission Service charges apply to all kWhs supplied under this tariff. A customer transition charge (CTC) also applies to all kWhs provided.

The Company objects to Staff's pricing proposal and the unjust disparity between the treatment of residential and non-residential customers (ComEd Ex. 31.0, p. 8). The Company also stated in rebuttal testimony (ComEd Ex. 20.0, p. 32) that "ComEd is not required to offer this service to customers…ComEd has not agreed to provide this service on any terms other than as proposed."

Staff provided testimony (ICC Staff Ex. No. 8.0) recommending the charge for Rider ISS for residential delivery service customers be the applicable bundled rate, plus a 10% adder.

Staff recommended this rate in order to reduce the barriers present for residential customers to participate in the competitive market. Some residential customers would not be able to withstand paying extremely high market prices for energy should they lose their supplier, particularly on a high cost day. Staff believes that a bundled rate is more appropriate for pricing power and energy to residential customers who have lost their alternative supplier, and that this Commission should approve a more appropriate rate format for Rider ISS for residential delivery services customers.

b. Commission Authority to Alter ComEd's Proposal

4. Other Customer Class Definition Issues

5. Residential Customer Eligibility for Rider PPO

6. SBO Credit

ComEd's proposal to set the SBO credit on the basis of avoided costs unfairly benefits the Company at the expense of competitors and consumers.

ComEd's avoided cost proposal would significantly reduce the unbundled service credits currently based on embedded costs. Specifically, it would reduce the SBO credit from the current $0.55 per bill to $0.03 per bill. (ICC Staff Ex. 7.0, p. 10).

The Company bases its proposal on economic efficiency. If alternative suppliers cannot beat the cost the utility avoids by not producing an unbundled service, Dr. Makholm believes that it would be more efficient for the utility to provide that service. If avoided costs drive away all competitors, Dr. Makholm argues that the Commission should not be concerned because that would reveal the utility to be a natural monopoly in the unbundled services market. (ICC Staff Ex. 7.0, p. 11).

The avoided cost approach is deficient and discriminatory.

The avoided cost approach suffers from three deficiencies. First, it is unfairly biased in favor of the utility. Second, it would effectively undermine delivery services unbundling. Third, it flies in the face of Commission precedent.

The avoided cost standard stacks the market for billing services in the utility's favor. While alternative suppliers must compete on the basis of their full cost of providing the unbundled service, utilities would be able to compete under a more relaxed standard, the costs they avoid by providing less. As long as the costs the utility avoids by not producing the service fall below the costs for competitors to provide the service, Drs. Gordon and Makholm would declare the utility to be the more efficient provider. They would continue to make that claim even if the utility had higher embedded costs and sold at a higher price than competitors (ICC Staff Ex. 7.0, pp. 11-12). This would undermine a basic tenet of the marketplace propounded by Adam Smith more than two centuries ago:

> It always is and must be the interests of the great body of the people to buy whatever they want of those who sell it cheapest. The proposition is so very manifest, that it seems ridiculous to take any pains to prove it; nor could it ever have been called into question had not the interested sophistry of merchants and manufacturers confounded the common sense of mankind.[8]

The Commission should reject ComEd's avoided cost standard to preserve this basic right for consumers.

> Dr. Makholm's statement that the utility may prove to be a natural monopolist for unbundled services under avoided cost pricing presents a particular concern.

Dr. Makholm's admission underscores the unfairness of the avoided cost standard. The institution of this costing standard could very well drive away all competition as Dr. Makholm admits. However, it would not be because the utility has demonstrated itself to be a natural monopoly for unbundled services. Instead, avoided costs would tilt the playing field so far in the utility's favor that there would be no reason

[8] Adam Smith *The Wealth of Nations* in *Economics Principles and Policies* by William Baumol and Alan Blinder (Harcourt Brace Jovanovich 1979), p. 488.

for competitors to remain in the market. In that situation there would be little point for the Commission to proceed with unbundling. (ICC Staff Ex. 7.0, p. 11).

ComEd's avoided cost approach clearly conflicts with Commission precedent.

The Commission addressed this issue directly in Docket No. 99-0013. After an extensive argument on the subject, the Commission reaffirmed its support for embedded costs over marginal costs as follows:

> Having considered the extensive record of this proceeding, the Commission finds no new factual basis for using anything other than an embedded cost approach to establish prices/credits for unbundled delivery services. Order, p. 49.

The Company has not offered any new arguments or evidence in this proceeding to justify any change to the Commission's position on the issue.

Dr. Makholm's claim that Staff's arguments for embedded costs represent an attack on ComEd's management is spurious.

Dr. Makholm has responded in curious fashion to Staff's contention that embedded costs serve as a measure of competitiveness by claiming this argument to be an attack upon ComEd's management. Dr. Makholm considers Mr. Lazare's statement that "the utilities that have been beset by high costs may have the most difficulty becoming competitive in the future" as an accusation that ComEd costs "are unjustly high" (ComEd Ex. 34.0, p. 7). Dr. Makholm goes on to explain the "logic" of this conclusion in response to discovery:

> The implication becomes even clearer when one considers that Mr. Lazare is recommending that alternative suppliers, who are permitted to price at marginal costs, need only undercut ComEd's average embedded cost. This evidences either a punitive desire to deprive ComEd of revenues or a belief—unsubstantiated though it is—that ComEd's embedded costs are too high (or both). (Staff Ex. 21, pp. 24-25).

The logic of this argument is indecipherable. For Dr. Makholm to construe the reasonable and, in fact, obvious statement that high cost utilities may have difficulty competing in the future as an attack on ComEd is clearly baseless. His further suggestion that this statement represents a "desire to deprive ComEd of revenues" is illogical as well. (ICC Staff Ex. 21.0, p. 25).

ComEd's proposed SBO credit based on avoided costs is clearly deficient.

ComEd proposes to replace the current embedded cost methodology for SBO credits with an avoided cost alternative. The net result of this proposal is a significant reduction in the SBO credit from the current 55 cents per bill to only 3 cents per bill (ICC Staff Ex. 7.0, p. 10) These figures clearly demonstrate the threat avoided costs pose to the unbundling process. If the avoided cost methodology were accepted, the paltry 3 cents per month SBO credit would effectively drive away alternative providers of billing services and enable ComEd to reestablish its monopoly in the marketplace. Thus, if the Commission wishes to promote competition in unbundled markets, it must begin by rejecting ComEd's proposed avoided cost credit for the SBO.

ComEd's proposal to include an onerous SBO offset to account for past due balances should be rejected.

ComEd has calculated an additional offset to the SBO of $4.58 per bill in the event that customers are allowed to take SBO service when they have past due balances on their electric bills (ICC Staff Ex. 7.0, p. 18). ComEd argues that it must engage in a labor-intensive process to oversee the collection of unpaid balances for SBO customers. However, Staff witness Schlaf has obviated the need for this offset by proposing that customers with past undue balances on bills not be allowed to switch to the SBO. This would enable ComEd to avoid the expense of keeping after customers that have gravitated to the SBO for their unpaid balances. The one condition for ComEd under Staff's proposal is that customers may be excluded from the SBO only if the Company can demonstrate that the unpaid balances do not stem from billing problems on its part. (ICC Staff Ex. 7.0, p. 19)

Staff's proposed SBO credit should be adopted in this proceeding.

Staff has proposed the only fair and reasonable SBO credit in this proceeding. That proposal begins with ComEd's own embedded cost analysis which calculates an SBO credit of 60 cents per bill. Staff then identifies two sets of offsetting costs to that credit depending on the nature of Electronic Data Interchange (EDI) transactions between the Company and the SBO provider. If those transactions take place over the Value Added Network (VAN), Staff accepts ComEd's calculation of a 27 cents per month offset, leaving a net SBO credit of 33 cents per month. If those transactions take place over ComEd's

Internet site, Staff recommends an offset of 3 cents per month, the level accepted by Ameren for Internet-based SBO offsets in its current deliver service docket 00-0802. This produces a net SBO credit of 57 cents per month based on transactions through the Internet. (ICC Staff Ex. 7.0, pp. 19-22).

Staff's proposed offset for Internet EDI exchanges is reasonable and should be adopted.

Under Staff's proposal, SBO providers would have the option of exchanging information with ComEd under the less costly Internet approach. This offers a significant advantage over the VAN network because it allows for direct exchange between the utility and SBO providers, thereby eliminating the middleman and its attendant costs. (ICC Staff Ex. 7.0, p. 20)

Staff proposal recognizes that Illinois utilities are gravitating towards the Internet as a medium for EDI exchanges. MidAmerican, CILCO and ComEd have acquired the capability for EDI exchanges through the Internet and AmerenCIPS and AmerenUE are moving to an Internet-based approach this year. (ICC Staff Ex. 7.0, p. 20)

The use of the Internet significantly reduces the cost of EDI exchanges between the utility and SBO provider according to information presented in the current delivery services proceeding for AmerenCIPS and AmerenUE (Docket No. 00-0802). In that case, Ameren calculated EDI offsets to the SBO of 35 cents per bill based on the VAN network. However, under the Internet approach, the Company and Staff agreed upon an EDI offset of only 3 cents per bill. (ICC Staff Ex. 7.0, p. 20)

This discussion is relevant for determining ComEd's SBO credit in three respects. First, the potentially lower cost Internet approach should be available to SBO as an alternative to EDI exchanges through the VAN. Ameren's ability to use this alternative for the SBO indicates that ComEd should be able to do the same. (ICC Staff Ex. 7.0, p. 20)

Second, the agreement reached between Ameren and Staff on the Internet-based SBO credit should serve as a benchmark for ComEd. Ameren's 3 cents per bill credit includes the cost of acquiring the necessary hardware to conduct Internet-based EDI exchanges. Since ComEd is already Internet-ready, it may be able to avoid some of these expenses. Furthermore, ComEd and Ameren employ a common software package for their Internet exchanges, ExpressDX, an indication that their operating costs will be comparable. Thus, ComEd's cost of using an Internet platform should be similar to the 3 cents per bill Internet offset for Ameren. (ICC Staff Ex. 7.0, p. 20)

Third, ComEd offered no response or criticisms in rebuttal to Staff's proposal for a 3 cents per month Internet-based SBO offset. Thus, the Commission has no basis in the record for modifying or rejecting Staff's proposal. (ICC Staff Ex. 7.0, p. 20)

7. Metering Service Charge Credit

ComEd's proposal to price unbundled metering on the basis of avoided costs unfairly benefits the Company at the expense of competitors and consumers.

ComEd's avoided cost proposal would significantly reduce unbundled service credits which are currently based on embedded costs. The current price of unbundled metering for ComEd customers ranges from $1.86 to $205.29 for non-residential customers. The Company's proposed avoided cost approach would reduce those credits to a range from $0.15 to $3.94 per month. (ICC Staff Ex. 7.0, p. 10)

As with the SBO credit, ComEd bases its proposal on economic efficiency. If alternative suppliers cannot beat the cost the utility avoids for not producing an unbundled service, Dr. Makholm believes that efficiency will be served by having the utility provide that service. Dr. Makholm argues that the Commission should not be concerned if an avoided cost price drives away metering competitors because that would mean the utility has a natural monopoly in the unbundled services market. (ICC Staff Ex. 7.0, p. 11)

The avoided cost approach is deficient and discriminatory.

The avoided cost approach for unbundling metering suffers from the same deficiencies as for billing. First, it is unfairly biased in favor of the utility. Second, it would effectively undermine delivery services unbundling. Third, it directly conflicts with Commission precedent on this costing issue.

The use of an avoided cost standard stacks the market for unbundled services in the utility's favor. In contrast to alternative suppliers who must compete on the basis of their full cost of providing the unbundled service, avoided costs enable utilities to compete under a more relaxed standard, the costs they avoid by providing less. As a result, the utility could succeed in the unbundled market even if its prices for these services are higher which would undermine the tenet propounded by Adam Smith more than two centuries ago that it always is and must be the interests of the great body of the people to buy whatever they want of those who sell it cheapest.[9]

[9] Adam Smith *The Wealth of Nations* in *Economics Principles and Policies* by William Baumol and Alan Blinder (Harcourt Brace Jovanovich 1979), p. 488.

As with billing services Dr. Makholm's statement that the utility may prove to be a natural monopolist for metering based on avoided cost pricing presents a particular concern. His admission underscores the unfairness of the avoided cost standard which, as Dr. Makholm admits, could very well drive away all competition. In that situation there would be little point for the Commission to proceed with unbundling. (ICC Staff Ex. 7.0, p. 11)

ComEd's avoided cost approach for metering clearly conflicts with Commission precedent.

The Commission addressed this issue directly in Docket No. 99-0013. After an extensive argument on the subject, the Commission reaffirmed its support for embedded costs over marginal costs as follows:

> Having considered the extensive record of this proceeding, the Commission finds no new factual basis for using anything other than an embedded cost approach to establish prices/credits for unbundled delivery services. Order, p. 49.

The Company has not offered any new arguments or evidence in this proceeding to justify any change to the Commission's position on the issue.

The hypothetical example presented by ComEd only serves to demonstrate why embedded costs provide a more reasonable foundation for unbundling delivery services.

Dr. Makholm introduces an example of a utility with 100 customers (ComEd Ex. 15.0, p. 10). The utility has an embedded cost of metering of $100 of which $75 is fixed and $25 is incremental. This works out on a monthly basis to 75 cents in fixed and 25 cents in incremental costs for individual customers. If that customer leaves for an alternative metering supplier, Dr. Makholm is concerned that either the utility or other customers would become responsible for the 75 cents in monthly fixed costs the customer had previously paid. Dr. Makholm finds the prospect of the utility assuming this cost to be "unacceptable" (ComEd Ex. 15.0, p. 11).

Dr. Makholm narrowly focuses on the potential impacts of an embedded cost approach to his own client, ComEd. He clearly lacks sympathy for the consumer in this example who must continue to pay 75 cents in fixed costs to the utility when an alternative supplier provides the service.

This hypothetical also reveals the limitations of Dr. Makholm's efficiency arguments. An alternative provider able to cover both his fixed and incremental costs by charging 75 cents per month could clearly beat the $1.00 per month the utility requires to recover his costs. In this situation, common sense clearly indicates that the alternative supplier is the more efficient provider. However, tortured logic leads Dr. Makholm to a different conclusion. He would only consider the alternative supplier more efficient if it could beat the utility's incremental cost of 25 cents per month. Since it cannot, Dr. Makholm finds the higher cost utility to be the more efficient supplier of metering services. This conclusion stands logic on its head.

Dr. Makholm's claim that Staff's arguments for embedded costs represent an attack on ComEd's management is spurious.

As explained with respect to the SBO, Dr. Makholm's effort to characterize Staff's contention that embedded costs serve as a measure of competitiveness as an attack upon ComEd's management is clearly misplaced. The logic of this argument is indecipherable. For Dr. Makholm to construe the reasonable and, in fact, obvious statement that high cost utilities may have difficulty competing in the future as an attack on ComEd is clearly baseless. His further suggestion that this statement represents a "desire to deprive ComEd of revenues" is illogical as well. (ICC Staff Ex. 21.0, p. 25)

Despite Dr. Makholm's accusation, embedded costs is an eminently reasonable approach to use for unbundling metering and should be adopted in this proceeding.

8. Rider TS – Transmission Service

9. 24 Month Return To Bundled Service Requirements

Staff agrees that Section 16-103(d) of the Act states that smaller-use customers who wish to return to bundled service are entitled to receive that service, but that the electric utility may require the former delivery services customers to remain on bundled service for up to 24 months. Thus, while electric utilities are entitled to impose a 24-month stay on bundled service for smaller-use customers, they are not required to do so. In Staff's opinion, an electric utility imposing a 24-month requirement would be imposing a harsh penalty on customers. As Dr. Schlaf pointed out, the 24-month requirement would be especially punitive towards those customers who might wish to return to delivery services (Staff Ex. 10.0, p. 16). If the Company wishes to use a 24-

month requirement, its proposed Rate RCDS should state that this requirement is "permitted by" the Act, rather than is "accordance with the Act," as the Company has proposed.

10. Rider 25

11. Other Topics

III. Terms and Conditions Issues

A. SBO Credit Eligibility (Customers With Past Due Bundled Service Balances)

The implementation of the plan to allow customers who claim that they have a legitimate billing dispute with ComEd to receive single billing services raises the question as to whether such customers should receive a single billing credit (Staff Ex. 10, p. 14). Dr. Schlaf recommended that such customers should receive the single billing credit, and the Company agreed to this recommendation (ComEd Ex. 31.0, pp. 42-43).

B. Enrollment Issues

Electronic Signatures and Letters of Agency

Staff has proposed that customers be allowed to switch providers over the Internet by executing the necessary documentation, known as a letter of agency ("LOA"), through electronic means. In prepared direct testimony, Staff witness Dr. Eric Schlaf explained that such a procedure would be an efficient and inexpensive means for providers to enroll new customers, reducing the providers' marketing costs (Staff Ex. 10.0, pp. 18-23). Dr. Schlaf also noted that the Commission has recently approved

Internet enrollments for gas utility customers in another case, Docket Nos. 00--0620/0621.

Although not expressly opposing Staff's recommendation, ComEd witnesses Sally Clair and Paul Crumrine stated in rebuttal panel testimony that the electronic signature issue warranted careful study. They further suggested that certain statutory provisions governing the process for switching electrical providers might not be easily reconciled with the relevant laws concerning electronic signatures (ComEd Ex. 31.0, pp. 51-54).

A review of the law in this area fully supports Staff's position and demonstrates that Internet signups are compatible with the pertinent statutory provisions.

In 1997, the General Assembly enacted a comprehensive program of legislation, the Electric Service Customer Choice and Rate Relief Law of 1997, which, among other things, established a retail direct access program for electricity customers in the state. 220 ILCS 5/16--101 through 16--130 (West 2000). In an effort to prevent "slamming," or the unauthorized transfer of a customer from one electrical service provider to another, section 16--115A(b) requires that an alternative retail electric supplier obtain "verifiable authorization from a customer, in a form or manner approved by the Commission consistent with Section 2EE of the Consumer Fraud and Deceptive Business Practices Act, before the customer is switched from another supplier." 220 ILCS 5/16--115A(b) (West 2000).

Section 2EE of the Consumer Fraud and Deceptive Business Practices Act (815 ILCS 505/2EE (West 2000)), which was part of the same package of legislation that produced the Rate Relief Law of 1997, specifies a number of requirements that a supplier must satisfy before switching a customer's service. To that end, section 2EE requires that the supplier obtain "the customer's written authorization" in a letter of agency (LOA). The LOA must be a separate document "whose sole purpose is to authorize an electric service provider change." In addition, the LOA must be printed in a readable typeface and "must be signed and dated by the subscriber requesting the electric service provider change." Moreover, the LOA may not be "combined with inducements of any kind on the same document."

Section 2EE also lists a number of pieces of information that the LOA must contain. In general terms, section 2EE requires that a letter of agency clearly and unambiguously confirm the subscriber's billing name and address, the decision to switch from the incumbent provider to the new provider, and the terms, conditions, and nature of the new service. In addition, the document must recite that a charge may be imposed for the change in service providers. A letter of agency may not suggest that the subscriber must take some action to retain the services of the incumbent provider. Section 2EE also provides that if any portion of the LOA is translated into a foreign language, then all parts of the LOA must be translated into that language.

Separately, section 2EE authorizes the use of checks to encourage customers to switch providers. Checks used for that purpose may contain only the information necessary to comply with the preceding provisions and whatever else is required to make the document a negotiable instrument. The check must also contain, "in easily readable, bold-face type on the face of the check, a notice that the consumer is authorizing an electric service provider change by signing the check. The letter of agency language also shall be placed near the signature line on the back of the check."

All of these provisions are compatible with the requirements of the Illinois electronic signature statute. The Electronic Commerce Security Act (5 ILCS 175/1--101 through 99--1 (West 2000)) ("ECSA") provides that electronic signatures may generally suffice when a written signature on a document is required. Section 5--115(a) of the ECSA, regarding electronic records, provides: "Where a rule of law requires information to be 'written' or 'in writing,' or provides for certain consequences if it is not, an electronic record satisfies that rule of law." 5 ILCS 175/5--115(a) (West 2000). Similarly, with respect to the requirement of a signature on a document, section 5--120(a) of the ECSA provides: "Where a rule of law requires a signature, or provides for certain consequences if a document is not signed, an electronic signature satisfies that rule of law." 5 ILCS 175/5--120(a) (West 2000).

A "rule of law" under ECSA is defined to include any statute, judicial decision, or other rule enacted or established by the State of Illinois or any of its agencies or commissions (5 ILCS 175/5--105 (West 2000)), and section 2EE therefore constitutes a "rule of law" for purposes of the electronic signature statute. The requirements of section 2EE for written and signed documentation evidencing the customer's decision to switch electrical service providers would appear to be satisfied by electronic signatures and electronic documents, as sections 5--115 and 5--120 of the ECSA establish.

To be sure, the rules expressed in sections 5--115(a) and 5--120(a) are subject to several exceptions. None of the specified exceptions, however, appear to be applicable here. Both provisions omit from their scope "any rule of law governing the creation or execution of a will or trust, living will, or healthcare power of attorney." 5 ILCS 175/5--115(b)(2), 5--120(c)(2) (West 2000). In addition, the provisions do not apply “to any record that serves as a unique and transferable instrument of rights and obligations,” such as negotiable instruments and other instruments of title, unless measures are taken to ensure that the electronic record is unique and any copy is readily identifiable as such. 5 ILCS 175/5--115(b)(3), 5--120(c)(3) (West 2000). The provisions also contain a more general exception. Section 5--115, regarding electronic records, may not be used

> when its application would involve a construction of a rule of law that is clearly inconsistent with the manifest intent of the lawmaking body or repugnant to the context of the same rule of law, provided that the mere requirement that information be ‘in writing,’ ‘written,’ or ‘printed’ shall not by itself be sufficient to establish such intent.

5 ILCS 175/5--115(b)(1).

Section 5--120, regarding electronic signatures, expresses the same exception in parallel terms, stating that it does not apply

> when its application would involve a construction of a rule of law that is clearly inconsistent with the manifest intent of the lawmaking body or repugnant to the context of the same rule of law, provided that the mere requirement of a ‘signature’ or that a record be ‘signed’ shall not by itself be sufficient to establish such intent.

5 ILCS 175/5--120(c)(1) (West 2000).

None of the enumerated exceptions preclude the Commission’s approval of a program authorizing the use of Internet enrollments, as Staff proposes. Wills, trusts, living wills, and healthcare powers of attorney are obviously not involved in this proceeding, so that exception has no relevance here. The special provision regarding negotiable instruments might or might not be relevant, depending on whether a provider attempts to use checks in conjunction with Internet enrollments, but the provision merely makes clear what additional measures would be necessary to comply with ECSA in that event.

Finally, there is nothing in the plain language of section 2EE to indicate that electronic signatures would be “inconsistent with the manifest intent” of the legislature in enacting the provision or “repugnant to the context” of that statute, as the further exception in sections 5--115(b)(1) and 5--120(c)(1) state. Section 2EE requires, of course, that a valid letter of agency contain certain specified information and be signed by the subscriber. Nothing in those requirements, however, suggests a legislative intent to preclude the use of electronic records and signatures in providing the necessary documentation. As section 5--115(b)(1) and 5--120(c)(1) of ECSA make clear, the mere use of the terms “in writing,” “written,” “printed,” “signature,” or “signed” is not sufficient to establish such intent. Inspection of section 2EE fails to reveal any further language or terms that could be construed as manifesting an intent by the legislature to bar the use of electronic or Internet signups for this purpose; an electronic LOA, made pursuant to the provisions of the Illinois electronic signature law, would thus appear to satisfy the requirements of section 2EE.

ComEd witnesses Clair and Crumrine also suggested, in general terms, and without specifying their areas of concern, that Internet signups under section 2EE might not be compatible with the federal electronic signature law. The Electronic Signatures in Global and National Commerce Act (known as the “E-SIGN Act”) took effect on October 1, 2000. 15 U.S.C. §§ 7001--06, 7021, 7031 (West 2000). Only if the federal law preempts the Illinois law does compliance with the federal law become an issue here, and it appears that the Illinois statute has not been preempted. The federal law employs narrow preemption provisions, preserving a large measure of state authority in this arena. A state statute may survive the preemptive force of the E-Sign Act if it specifies alternative procedures or requirements for electronic records and signatures that are consistent with the requirements of the federal legislation and if those requirements do not favor a specific technology for the performing the functions of, among other things, creating, storing, and authenticating electronic records. 15 U.S.C. § 7002. The Illinois electronic signature law appears to satisfy these provisions. Writing before enactment of the federal law, one drafter of the Illinois electronic signature law believed that, under the version of the federal preemption provisions then being proposed by the House of Representatives, the Illinois statute would survive preemption (Robertson, The Illinois Electronic Commerce Security Act: A Reply to Martin Behn, 24 S. Ill. U.L.J. 473, 511-12); the preemption provisions that found their way into the federal statute were largely similar to the provisions discussed by the drafter.

Finally, even if the Illinois electronic signature law were preempted by the Federal statute, there is no reason to believe that the procedures required by section 2EE would not satisfy the federal statute. As a general matter, Internet enrollments for utility services are compatible with the federal statute. It may be noted that state utility commissions in other jurisdictions have permitted customers to select service providers by way of the Internet in similar circumstances. Thus, in New Jersey and Georgia, to name two, customers may select their electric (New Jersey) and gas (Georgia) suppliers over the Internet. The New Jersey public utility commission even cited the Federal law as providing the impetus for the removal of a previously imposed limitation on the percentage of customers allowed to switch suppliers over the Internet. See

Report of the E-Commerce Committee, 22 Energy L.J. 179, 183 (2001) (citing In the Matter of the Electric Discount and Energy Competition Act of 1999--Internet Enrollment Program, Docket Nos. EX94120585Y (Sept. 12, 2000)). Nor has ComEd pointed to any provision in section 2EE that would require a different result here.

C. Release and Use of Customer Specific Information

D. Off-Cycle Or Non-Standard Switching For Residential Customers

Dr. Schlaf proposed that the Company permit residential customers to switch on an off-cycle or non-standard basis (i.e., to switch on a date other than the customer's regularly scheduled switch date) (Staff Ex. 24.0, pp. 4-5). The Company responded that it would be willing to offer a fee-based off-cycle switching service for residential Interim Supply Services customers, except perhaps in situations where a Retail Electric Supplier "places" a large number of customers on Interim Supply Service at the same time (ComEd Ex. 31.0, p. 46). The fee that would be charged is the same fee that is now charged to non-residential customers, and the charge would only apply when a meter reading is required (ComEd Ex. 42.0, p. 22). Staff does not oppose the proposal to extend off-cycle/non-standard switching to only residential Interim Supply Service customers. However, Staff notes that, should residential customers appear to demand non-standard switching in the future, Staff might ask the Commission to order ComEd to provide non-standard switching to residential customers on a larger-scale basis.

E. General Account Agency Issues

ComEd proposes that customers who wish to employ "account agents" should sign a specific form that makes clear that ComEd will act on requests made by the customers' agents as if the customers themselves had made the requests. The form was proposed with the Company's direct testimony, and was revised in the rebuttal panel testimony of ComEd witnesses Claire and Crumrine. These witnesses indicate the form would be easily obtainable by customers and suppliers (Tr. 1114). The form would not be required retrospectively for customers who already have agents representing them with respect to ComEd's electric service (Tr. 1115).

As Dr. Schlaf pointed out, the use of account agents has become so common in the electric (and natural gas) industries that it is reasonable for utilities to be able to show that they have informed customers of the risks inherent in using account agents (Staff Ex. 10.0, p. 2). Staff has no objection to the use of a form that would help ensure customers have the opportunity to become aware that their agent will receive the correspondence, including bills, that otherwise would be sent to them. The form, however, states that the customer whose service is in danger of being disconnected will not receive a disconnection notice if the customer has employed an agent. While Staff has no objection to an account agent receiving the disconnection notice, Staff believes that the customer should also receive the disconnection notice to ensure that the customer is aware that its service could be disrupted.

It is Staff's understanding that if the Company were directed by the Commission to send a duplicate disconnection notice to the customer (as well as the agent), ComEd would charge the customer a $2.00 fee. Staff would prefer that the costs the Company incurs to provide duplicate disconnection notices be included in the Company's distribution revenue requirement, so the customer receiving the disconnection would not also receive a bill for $2.00 (Staff Ex. 24.0, p. 2).

F. Value-Added Aggregation Services

G. Collection of FERC Charges Under DSTs

ComEd proposes to maintain the requirement in its delivery services tariffs (DSTs) that holds retail customers financially responsible for the unpaid portion of their RES' (or other entity's) transmission bill. (ComEd Ex. 13.0, Attachment C, Rider TS, PURPOSE.) This requirement is unnecessary because ComEd currently has at its disposal, the ability to impose credit security requirements on RESs who apply for transmission service under the Company's Open Access Transmission Tariff (OATT). In addition, the Illinois Commerce Commission (ICC or the Commission) requires that Alternative Retail Electric Suppliers (ARES), which are a subset of RESs, meet reasonable credit security requirements upon receiving their certificate to serve retail customers. (See Part 451 IL Admin. Code) Furthermore, if ComEd becomes a member of a FERC approved regional transmission organization (RTO), e.g., the Alliance RTO (ARTO), then transmission services will be provided by the ARTO, not ComEd. Under the ARTO's proposed OATT, the ARTO can impose credit security requirements on RESs (ARTO OATT, Vol. I Original Sheet No. 39, Section 11 Creditworthiness), who are transmission customers, and the ARTO can charge bad debt expense to all transmission customers (RESs or other entities) on a monthly basis when a transmission customer defaults on payments. (ARTO OATT, Vol. I Original Sheet No. 283, Schedule 10, Administrative Fee, Section (4)) Thus, it is unnecessary to bill retail customers for the unpaid transmission bills of their RES when so many other measures are in place to protect the transmission provider against a transmission customer's default.

Staff is not arguing that the current credit security requirements imposed by the Commission, or available to the transmission provider via the OATT, are inadequate or that they will perfectly protect the transmission provider and the retail customer from supplier default situations. Rather, the many credit security requirements in place are reasonable and given that the RES is the Transmission Customer and the RES has the specific knowledge and expertise that is required to procure transmission service, the retail customer should not be required to provide an additional level of insurance against unpaid bills for the transmission provider and the RES.

In addition to being unnecessary, ComEd's proposal is unreasonable because it does not provide full disclosure to the retail customer regarding the financial liability the retail customer assumes (via ComEd's delivery services tariffs and OATTs). Further, it would be unreasonable to assume an agency relationship between the retail customer and the RES that would otherwise allow ComEd to bill the retail customer for the unpaid transmission bill of the designated RES acting on the customer's behalf.

Bundled retail service is different than unbundled service, and this is especially true for unbundled retail transmission service. Once a customer moves to delivery services, the transmission service is unbundled and must be procured by the customer or some other entity, e.g., a RES. Retail customers, other than a select few, have no knowledge or expertise in procuring transmission service and the latter will be provided by the retail customer's RES or other entity. In general, transmission service includes, but is not limited to, applying for the service, designating the type of transmission service, e.g., firm, non-firm, network integrated service, and procuring several ancillary services, e.g., Scheduling, Reactive Supply and Voltage Control, Regulation and Frequency Response, Energy Imbalance Service, Operating Reserve – Spinning Reserve, Operating Reserve – Supplemental Reserve. In order to procure these services, a customer must be knowledgeable of the utility's OATTs and their Open Access SameTime Information System (OASIS). Retail customers would also have to be knowledgeable of the loads of other customers served by their RES to accurately estimate their charges for transmission service. Staff points out that the knowledge of other retail customers' loads is not even required of a Customer Self Manager who procures their own transmission service. It is unreasonable, to say the least, to claim that retail customers, in general, have any knowledge or expertise in directly procuring these services. Whether transmission service is procured and utilized properly will depend upon the expertise and knowledge of the retail customer's RES (or other entity), and the RES should be billed accordingly, not the retail customer.

ComEd's retail tariff is not the appropriate vehicle for establishing that an agency relationship exists between the retail customer and the RES that allows ComEd to bill the retail customer for the unpaid transmission bill of the RES. If the Company wants to bill the retail customer for a RES's unpaid transmission bill, it needs to find the necessary agency relationship elsewhere, e.g., in the terms and conditions of the contract between the RES and the retail customer. The Letters of Agency ("LOA") between retail customer and electric supplier, required under the Consumer Fraud and Deceptive Business Practices Act, simply authorize an electric service provider change.

Unless the LOA, or some other agreement, between the RES and retail customer also sets forth the terms and conditions of transmission service, the customer's authority to control the method and manner in which the RES procures transmission service, and the applicable charges for which retail customers will be ultimately responsible, there is no evidence of agency relationship between the RES and retail customer permitting a utility to make such demands of the retail customer through the utility's tariffs. ComEd's tariff-based assertions that a RES is acting as a retail customer's agent does not, in and of itself, make such customers responsible for the unpaid transmission bills of their so-called agents.

ComEd claims that the reason for requiring retail customers to pay for the unpaid transmission bills of their RES is to promote retail competition by lowering the credit security requirements costs of the RES. (ComEd witness Sterling, ComEd Ex. 16.0, pp. 26-28) However, this is not a legitimate reason for **requiring** this from retail customers in the utility tariffs. Although it is possible that ComEd's requirement may lower the credit security requirement costs to RESs, it is not appropriate to potentially lower the costs of the RES by shifting ultimate responsibility for those costs to uninformed retail customers who are not able to take actions to mitigate the risks of nonperformance by their RES.

Consider the following hypothetical: Assume that the largest energy trading company in the world, End-Run, suffers a crisis in investor confidence and files for Chapter 11 Bankruptcy, and End-Run provides electric supply and procures transmission service to serve retail customers in ComEd's service area. End-Run's unpaid bill for transmission service to ComEd (or the ARTO) is $20 million. Under

ComEd's proposal, the retail customers of End-Run are ultimately responsible for the $20 million that End-Run owes to ComEd (or the ARTO) Assume that End-Run and ComEd's parent company, Exelon, entered into wholesale power and energy agreements but End-Run is now unable to fulfill its obligations under those agreements. As it turns out, Exelon's transactions with End-Run were secured and Exelon is now in a position where it will receive $18 million of the $20 million from End-Run. In the Exelon case, Exelon understood the risks inherent to business transactions with End-Run and Exelon chose to negotiate secured business transactions. Retail customers should be afforded the same opportunity to negotiate this financial responsibility with their RES. If retail customers are afforded this option, then it will encourage full disclosure of this responsibility of the terms and conditions of transmission service and potential risks associated with assuming this responsibility for retail customers. Nothing prevents a RES from explaining this liability to retail customers and negotiating it as part of their retail service. However, the ComEd tariff language makes it unnecessary because the tariff language automatically assigns ultimate responsibility to retail customers. Thus, the ComEd position may lower a RES's credit security costs while encouraging retail customers to remain uninformed and in the dark regarding their financial liability for transmission service. Neither ComEd nor Exelon would negotiate such a position for itself.

ComEd also claims that their proposal will lower the billing costs of the ARTO. (ComEd Ex. 36.0, p. 3) This possible outcome is irrelevant. ComEd can act as the billing agent for the ARTO for those retail customers who have voluntarily agreed to accept ultimate financial liability for transmission service, and thus save the ARTO the expense of billing those retail customers for unpaid transmission bills of their RES without having the requirement in the ComEd delivery services tariffs. However, there is no indication that the ARTO even contemplates this measure given that the ARTO's OATT sets forth the terms and conditions for credit security requirements for transmission customers and for billing all transmission customers for the unpaid transmission bills in the event of a default of a transmission customer. The ARTO has thought through this potential problem to some degree and must have a billing system to function in this manner. There is no need for ComEd to impose this requirement on retail customers in delivery services tariffs in order to act as the billing agent of the ARTO.

IV. Other Issues

A. Single Billing[10]

ComEd initially proposed to prohibit residential delivery services customers from receiving single billing services if they have any unpaid balances with ComEd for their past receipt of bundled services (Staff Ex. 10.0, p. 11). ComEd's plan was prompted by a decision in the Commission's order in Docket No. 00-0494 (the "Uniformity" proceeding), in which the Commission decided that suppliers should not be required to collect outstanding bundled balances on behalf of electric utilities. ComEd responded to the Commission's decision by devising certain processes to perform the collection activities that ComEd would have preferred be performed by suppliers. Since performing these processes for the potentially large volume of residential customers who might wish to have single billing service while they still owe bundled balances,

[10] Addition to ALJ outline

ComEd decided to prohibit residential customers from taking single billing service while they still owe money to ComEd (Id., pp. 11-12).

Dr. Schlaf noted that ComEd's proposal could present a potential problem because it could penalize the customers who owe bundled balances only because of ComEd's billing errors. Thus, Dr. Schlaf recommended that ComEd's proposal be amended to allow customers who have a legitimate billing dispute with ComEd to receive single billing services (Id., p. 13).

ComEd responded to Dr. Schlaf's recommendation by amending its tariff to state that a customer with a legitimate billing dispute may be placed on single billing by its Retail Electric Supplier (ComEd Ex. 31.0, pp. 40-41). Staff has no objection to the revised provisions in ComEd's Rate RCDS. However, Staff notes that the usefulness of this policy may depend on the timing of ComEd's determination as to whether a customer has a bundled balance. ComEd is willing to meet with interested parties to create a workable process for identifying when a customer has a bundled balance and therefore may be ineligible for single billing. If the process proves to be workable, Staff believes the Commission may need to revisit the issue yet again (ComEd Ex. 31.0, p. 44).

Staff recommends that ComEd keep records of the number of customers, both residential and non-residential, who attempt to switch to single billing services while owing bundled balances. Staff also recommends that ComEd track the reasons why such customers have outstanding balances and the amount of unpaid charges associated with the bundled balances. ComEd should record whether the customer has a bundled balance because (a) the customer has a legitimate billing dispute or (b) the customer has been billed accurately and in a timely manner, but has simply not paid its bills on-time. Staff recommends that ComEd provide this information to the Commission by approximately May 2003, along with an assessment as to whether the changes to Rider SBO have proved to be an acceptable solution to the issue of unpaid balances (Staff Ex. 24.0, p. 4).

B. Customer Aggregation and Targeted Consulting Services[11]

ComEd indicates that it will enter into agreements with affiliated and non-affiliated suppliers for Customer Aggregation and Targeted Consulting services. (ComEd Ex. 12.0, pp. 56-57) Staff is concerned about these agreements because the Company has provided no details and no drafts of the agreements. There is nothing to evaluate here except the word of the Company. Staff recommends that each contract, under these categories, between ComEd and an affiliated interest, be filed with the Illinois Commerce Commission within 30 days of the signed date of the contract. In addition, Staff recommends that ComEd file each contract with its 3 largest non-affiliated entities (determined by dollar value of the contracts), within 30 days of the signed date of the contract. The contracts shall be filed with the Manager of the Energy Division or its successor office, for informational purposes, but subject to review for compliance with the Commission's rules concerning non-discrimination and functional separation. (ICC Staff Ex. 11.0, pp. 14-15)

[11] Addition to ALJ outline

Staff is not implying that ComEd will engage in inappropriate behavior with respect to the services provided and the Commission's rules regarding affiliated interests and functional separation. Staff points out that there is a strong incentive for incumbent utilities to favor their affiliates over non-affiliated suppliers, i.e., because the Act does not require divestiture between delivery services and generation every incumbent utility that has generation affiliates or affiliates that market power to retail customers has an incentive to favor those affiliates. Staff's recommendation attempts to address behavior that may result from those incentives. Until those incentives are eliminated, and most likely they will exist for the foreseeable future, then the Commission will have to address them via this more cumbersome approach, i.e., through rules, contract filings, and enforcement measures. Staff's position is not that ComEd refrain from entering into agreements to provide worthwhile services to its affiliate and non-affiliates as contemplated by the Company. Staff's concern is that in the absence of seeing the contracts, the Commission will not be able to verify for itself the claims of the Company. (ICC Staff Ex. 25.0, pp. 7-8)

CONCLUSION

For the foregoing reasons, the Staff of the Illinois Commerce Commission respectfully requests that the Commission accept Staff's recommendations.

Respectfully submitted,

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Illinois Commerce Commission

December 10, 2001

Commonwealth Edison Company
Statement of Operating Income with Adjustments
For the Test Year Ending December 31, 2000
(Thousands)

Line No.	Description	Company Pro Forma (ComEd Ex. 4.0 Sch. C-1)	Staff Adjustments (Appendix A Sch. 2)	Staff-Adjusted Company Pro Forma (Cols. B+C)	Staff's Adjustment To Company's Proposed Revenues	Staff Pro Forma Proposed (Cols. D+E)
	(A)	(B)	(C)	(D)	(E)	(F)
1	Operating Revenues	$ 1,786,970	-	$ 1,786,970	$ (266,615)	$ 1,520,355
2	Other Revenues	54,799	-	54,799	-	54,799
3	Total Operating Revenues	1,841,769	-	1,841,769	(266,615)	1,575,154
4	Uncollectible Expense	16,300	(3,605)	12,695	(1,893)	10,802
5	Production	432	-	432	-	432
6	Distribution	418,141	(39,652)	378,489	-	378,489
7	Customer Accounts	166,136	(9,967)	156,169	-	156,169
8	Customer Service and Informational	12,217	-	12,217	-	12,217
9	Administrative and General	200,663	(82,510)	118,153	-	118,153
10	Depreciation and Amortization	299,127	(2,257)	296,870	-	296,870
11	Taxes Other than Income Taxes	154,826	(4,726)	150,100	-	150,100
12	Total Operating Expense					
13	Before Income Taxes	1,267,842	(142,717)	1,125,125	(1,893)	1,123,232
14	State Income Tax	33,952	10,992	44,944	(18,742)	26,202
15	Federal Income Tax	155,958	50,485	206,443	(86,093)	120,350
16	Deferred Taxes and ITCs Net	(22,334)	-	(22,334)	-	(22,334)
17	Total Operating Expenses	1,435,418	(81,240)	1,354,178	(106,728)	1,247,450
18	NET OPERATING INCOME	$ 406,351	$ 81,240	$ 487,591	$ (159,887)	$ 327,704
19	Staff Rate Base (Appendix A, Schedule 3, Column (D))					$ 3,645,203
20	Staff Overall Rate of Return (ICC Staff Exhibit 27.0, Schedule 27.1)					8.99%
21	Revenue Change (Col. (F), Line 3 minus Col. (B), Line 3)					$ (266,615)
22	Percentage Change to Company Proposed Revenues (Col. (F), Line 21 divided by Col. (B), Line 3)					-14.48%

Commonwealth Edison Company
Adjustments to Operating Income
For the Test Year Ending December 31, 2000
(Thousands)

Line No.	Description	Interest Synchronization (Appendix A Sch. 5)	Retired Plant (St. Ex. 1.0 Sch. 1.1)	Replaced Plant (St. Ex. 1.0 Sch. 1.2)	Interest on Customer Deposits (St. Ex. 2.0 Sch. 2.2)	Uncollectible Expense (St. Ex. 2.0 Sch. 2.3)	Collection Agency Expense (St. Ex. 2.0 Sch. 2.4)	State Use Tax Expense (St. Ex. 2.0 Sch. 2.5)	Subtotal Operating Statement Adjustments
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
1	Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Other Revenues	-	-	-	-	-	-	-	-
3	Total Operating Revenues	-	-	-	-	-	-	-	-
4	Uncollectible Expense	-	-	-	-	(3,605)	-	-	(3,605)
5	Production	-	-	-	-	-	-	-	-
6	Distribution	-	-	-	-	-	-	-	-
7	Customer Accounts	-	-	-	-	-	(1,106)	-	(1,106)
8	Customer Service and Informational	-	-	-	-	-	-	-	-
9	Administrative and General	-	-	-	(919)	-	-	-	(919)
10	Depreciation and Amortization	-	(858)	(279)	-	-	-	-	(1,137)
11	Taxes Other than Income Taxes	-	-	-	-	-	-	(1,401)	(1,401)
12	Total Operating Expense								
13	Before Income Taxes	-	(858)	(279)	(919)	(3,605)	(1,106)	(1,401)	(8,168)
								-	
14	State Income Tax	886	61	20	65	255	78	99	1,464
15	Federal Income Tax	4,070	279	91	299	1,172	360	456	6,727
16	Deferred Taxes and ITCs Net	-	-	-	-	-	-	-	-
17	Total Operating Expenses	4,956	(518)	(168)	(555)	(2,178)	(668)	(846)	23
18	NET OPERATING INCOME	$ (4,956)	$ 518	$ 168	$ 555	$ 2,178	$ 668	$ 846	$ (23)

Commonwealth Edison Company
Adjustments to Operating Income
For the Test Year Ending December 31, 2000
(Thousands)

Line No.	Description	Subtotal	Tree Management Expense (St. Ex. 2.0 Sch. 2.6)	Employee Layoffs (St. Ex. 17.0 Sch. 17.10)	Salary & Wages Inc. Comp (St. Ex. 17.0 Sch. 17.11)	Salary & Wages Inc. Comp (St. Ex. 17.0 Sch. 17.11)	Payroll Tax (St. Ex. 17.0 Sch. 17.13)	Storm Restoration Expense (St. Ex. 17.0 Sch. 17.7)	Subtotal Operating Statement Adjustments
	(A)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)
1	Operating Revenues	$ -	$ -	$ -			$ -	$ -	$ -
2	Other Revenues	-	-	-	-	-	-	-	-
3		-	-	-	-	-	-	-	-
4	Uncollectible Expense	(3,605)	-	-	-	-	-	-	(3,605)
5	Production	-	-	-	-	-	-	-	-
6	Distribution	-	(7,028)	-	-	(12,380)	-	(10,505)	(29,913)
7	Customer Accounts	(1,106)	-	(8,096)	-	-	-	-	(9,202)
8	Customer Service and Informational	-	-	-	-	-	-	-	-
9	Administrative and General	(919)	-	-	(12,181)	-	-	-	(13,100)
10	Depreciation and Amortization	(1,137)	-	-	-	-	-	-	(1,137)
11	Taxes Other than Income Taxes	(1,401)	-	-	-	-	(3,325)	-	(4,726)
12	Total Operating Expense								
13	Before Income Taxes	(8,168)	(7,028)	(8,096)	(12,181)	(12,380)	(3,325)	(10,505)	(61,683)
14	State Income Tax	1,464	498	573	862	877	235	744	5,253
15	Federal Income Tax	6,727	2,286	2,633	3,962	4,026	1,081	3,416	24,131
16	Deferred Taxes and ITCs Net	-	-	-	-	-	-	-	-
17	Total Operating Expenses	23	(4,244)	(4,890)	(7,357)	(7,477)	(2,009)	(6,345)	(32,299)
18	NET OPERATING INCOME	$ (23)	$ 4,244	$ 4,890	$ 7,357	$ 7,477	$ 2,009	$ 6,345	$ 32,299

Commonwealth Edison Company
Adjustments to Operating Income
For the Test Year Ending December 31, 2000
(Thousands)

Line No.	Description	Subtotal	Bill Payment Center Closings (St. Ex. 17.0 Sch. 17.8)	Charitable Contributions (St. Ex. 4.0 Sch. 4.1)	Advertising Expense (St. Ex. 18.0 Sch. 18.1)	Bank Commitment Fees (St. Ex. 4.0 Sch. 4.3)	Social & Service Club Dues (St. Ex. 18.0 Sch. 18.2)	Research & Development (St. Ex. 4.0 Sch. 4.6)	Subtotal Operating Statement Adjustments
	(A)	(R)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)
1	Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Other Revenues	-	-	-	-	-	-	-	-
3	Total Operating Revenues	-	-	-	-	-	-	-	-
4	Uncollectible Expense	(3,605)	-	-	-	-	-	-	(3,605)
5	Production	-	-	-	-	-	-	-	-
6	Distribution	(29,913)	-	-	-	-	-	-	(29,913)
7	Customer Accounts	(9,202)	(765)	-	-	-	-	-	(9,967)
8	Customer Service and Informational	-	-	-	-	-	-	-	-
9	Administrative and General	(13,100)	-	(110)	(1,199)	(902)	(15)	(3,529)	(18,855)
10	Depreciation and Amortization	(1,137)	-	-	-	-	-	-	(1,137)
11	Taxes Other than Income Taxes	(4,726)	-	-	-	-	-	-	(4,726)
12	Total Operating Expense								
13	Before Income Taxes	(61,683)	(765)	(110)	(1,199)	(902)	(15)	(3,529)	(68,203)
14	State Income Tax	5,253	54	8	85	64	1	250	5,715
15	Federal Income Tax	24,131	249	36	390	293	5	1,148	26,252
16	Deferred Taxes and ITCs Net	-	-	-	-	-	-	-	-
17	Total Operating Expenses	(32,299)	(462)	(66)	(724)	(545)	(9)	(2,131)	(36,236)
18	NET OPERATING INCOME	$ 32,299	$ 462	$ 66	$ 724	$ 545	$ 9	$ 2,131	$ 36,236

Commonwealth Edison Company
Adjustments to Operating Income
For the Test Year Ending December 31, 2000
(Thousands)

Line No.	Description	Subtotal	Plant Placed in Service 2nd Quarter 2001 (St. Ex. 15.0 Sch. 15.1)	Contractors' Premiums (St. Ex. 15.0 Sch. 15.2)	Overtime (St. Ex. 15.0 Sch. 15.3)	Distribution Salaries & Wages (St. Ex. 17.0 Sch. 17.12)	Legal (St. Ex. 18.0 Sch. 18.3)	Labor Allocator (St. Ex. 19.0 Sch. 19.2, p. 2)	Total Operating Statement Adjustments
	(A)	(Z)	(AA)	(BB)	(CC)	(DD)	(EE)	(FF)	(GG)
1	Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Other Revenues	-	-	-	-	-	-	-	-
3	Total Operating Revenues	-	-	-	-	-	-	-	-
4	Uncollectible Expense	(3,605)	-	-	-	-	-	-	(3,605)
5	Production	-	-	-	-	-	-	-	-
6	Distribution	(29,913)	-	-	-	(9,739)	-	-	(39,652)
7	Customer Accounts	(9,967)	-	-	-	-	-	-	(9,967)
8	Customer Service and Informational	-	-	-	-	-	-	-	-
9	Administrative and General	(18,855)	-	-	-	-	(3,653)	(60,002)	(82,510)
10	Depreciation and Amortization	(1,137)	(277)	(603)	(240)	-	-	-	(2,257)
11	Taxes Other than Income Taxes	(4,726)	-	-	-	-	-	-	(4,726)
12	Total Operating Expense								
13	Before Income Taxes	(68,203)	(277)	(603)	(240)	(9,739)	(3,653)	(60,002)	(142,717)
14	State Income Tax	5,715	20	43	17	690	259	4,248	10,992
15	Federal Income Tax	26,252	90	196	78	3,167	1,188	19,514	50,485
16	Deferred Taxes and ITCs Net	-	-	-	-	-	-	-	-
17	Total Operating Expenses	(36,236)	(167)	(364)	(145)	(5,882)	(2,206)	(36,240)	(81,240)
18	NET OPERATING INCOME	$ 36,236	$ 167	$ 364	$ 145	$ 5,882	$ 2,206	$ 36,240	$ 81,240

Commonwealth Edison Company
Rate Base
For the Test Year Ending December 31, 2000
(Thousands)

Line No.	Description	Company Pro Forma Rate Base (ComEd Ex. 4.0 Sch. B-1)	Staff Adjustments (St. Ex. 17.0 Sch. 17.4)	Staff Pro Forma Rate Base (Col. B+C)
	(A)	(B)	(C)	(D)
1	Distribution Plant	$ 8,370,615	$ (80,219)	$ 8,290,396
2	General and Intangible Plant	850,351	(405,161)	445,190
3	Accumulated Depreciation - Distribution Plant	(3,821,634)	44,715	(3,776,919)
4	Accumulated Depreciation - General and Intangible Plant	(224,207)	1,035	(223,172)
5	Net Plant	5,175,125	(439,630)	4,735,495
6	Additions to Rate Base			
7	Materials and Supplies Inventories	36,479	-	36,479
8	Construction Work in Progress	20,813	-	20,813
9	Regulatory Assets	6,161	-	6,161
10	Deductions From Rate Base			
11	Accumulated Deferred Income Taxes	(765,927)	1,071	(764,856)
12	Customer Deposits	(17,856)	-	(17,856)
13	Budget Payment Plan Balances	-	(165)	(165)
14	Customer Advances	(325)	-	(325)
15	Other Deferred Credits	(9,820)	-	(9,820)
16	Accumulated Investment Tax Credits	(254)	-	(254)
17	Operating Reserves	(360,469)	-	(360,469)
18	Rate Base	$ 4,083,927	$ (438,724)	$ 3,645,203

Commonwealth Edison Company
Adjustments to Rate Base
For the Test Year Ending December 31, 2000
(Thousands)

Line No.	Description	Retired Plant (St. Ex. 1.0 Sch. 1.1)	Retired Plant (St. Ex. 1.0 Sch. 1.1)	Replaced Plant (St. Ex. 1.0 Sch. 1.2)	Replaced Plant (St. Ex. 1.0 Sch. 1.2)	Budget Payment Plan Balances (St. Ex. 2.0 Sch. 2.1)	Plant Placed in Service 2nd Quarter 2001 (St. Ex. 15.0 Sch. 15.1)	Plant Placed in Service 2nd Quarter 2001 (St. Ex. 15.0 Sch. 15.1)	Subtotal Rate Base Adjustments
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
1	Distribution Plant	$ (32,157)	$ -	$ (11,060)	$ -	$ -	$ -	$ -	$ (43,217)
2	General and Intangible Plant	-	-	-	-	-	-	-	-
3	Accumulated Depreciation - Distribution Plant	-	32,157	-	11,060	-	-	277	43,494
4	Accumulated Depreciation - General and Intangible Plant	-	-	-	-	-	-	-	-
5	Net Plant	(32,157)	32,157	(11,060)	11,060	-	-	277	277
6	Additions to Rate Base								-
7	Materials and Supplies Inventories	-	-	-	-	-	-	-	-
8	Construction Work in Progress	-	-	-	-	-	-	-	-
9	Regulatory Assets	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-
10	Deductions From Rate Base	-	-	-	-	-	-	-	-
11	Accumulated Deferred Income Taxes	-	-	-	-	-	52	-	52
12	Customer Deposits	-	-	-	-	-	-	-	-
13	Budget Payment Plan Balances	-	-	-	-	(165)	-	-	(165)
14	Customer Advances	-	-	-	-	-	-	-	-
15	Other Deferred Credits	-	-	-	-	-	-	-	-
16	Accumulated Investment Tax Credits	-	-	-	-	-	-	-	-
17	Operating Reserves	-	-	-	-	-	-	-	-
18	Rate Base	$ (32,157)	$ 32,157	$ (11,060)	$ 11,060	$ (165)	$ 52	$ 277	$ 164

Commonwealth Edison Company
Adjustments to Rate Base
For the Test Year Ending December 31, 2000
(Thousands)

Line No.	Description	Subtotal	Plant Placed in Service 2nd Quarter 2001 (St. Ex. 15.0 Sch. 15.1)	Contractors' Premiums (St. Ex. 15.0 Sch. 15.2)	Contractors' Premiums (St. Ex. 15.0 Sch. 15.2)	Contractors' Premiums (St. Ex. 15.0 Sch. 15.2)	Overtime (St. Ex. 15.0 Sch. 15.3)	Overtime (St. Ex. 15.0 Sch. 15.3)	Subtotal Rate Base Adjustments
	(A)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)
1	Distribution Plant	$ (43,217)	$ (11,038)	$ -	$ (16,742)	$ -	$ -	$ (9,222)	$ (80,219)
2	General and Intangible Plant	-	-	-	-	-	-	-	-
3	Accumulated Depreciation - Distribution Plant	43,494	-	904	-	-	317	-	44,715
4	Accumulated Depreciation - General and Intangible Plant	-	-	-	-	-	-	-	-
5	Net Plant	277	(11,038)	904	(16,742)	-	317	(9,222)	(35,504)
6	Additions to Rate Base								-
7	Materials and Supplies Inventories	-	-	-	-	-	-	-	-
8	Construction Work in Progress	-	-	-	-	-	-	-	-
9	Regulatory Assets	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-
10	Deductions From Rate Base	-	-	-	-	-	-	-	-
11	Accumulated Deferred Income Taxes	52	-	-	-	369	-	-	421
12	Customer Deposits	-	-	-	-	-	-	-	-
13	Budget Payment Plan Balances	(165)	-	-	-	-	-	-	(165)
14	Customer Advances	-	-	-	-	-	-	-	-
15	Other Deferred Credits	-	-	-	-	-	-	-	-
16	Accumulated Investment Tax Credits	-	-	-	-	-	-	-	-
17	Operating Reserves	-	-	-	-	-	-	-	-
18	Rate Base	$ 164	$ (11,038)	$ 904	$ (16,742)	$ 369	$ 317	$ (9,222)	$ (35,248)

Commonwealth Edison Company
Adjustments to Rate Base
For the Test Year Ending December 31, 2000
(Thousands)

Line No.	Description	Subtotal	Overtime (St. Ex. 15.0 Sch. 15.3)	Labor Allocator (St. Ex. 19.0 Sch. 19.2, p. 2)	Labor Allocator (St. Ex. 19.0 Sch. 19.2, p. 2)	Labor Allocator (St. Ex. 19.0 Sch. 19.2, p. 2)	(Source)	(Source)	Total Rate Base Adjustments
	(A)	(R)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)
1	Distribution Plant	$ (80,219)	$ -	$ -	$ -	$ -	$ -	$ -	$ (80,219)
2	General and Intangible Plant	-		(405,161)					(405,161)
3	Accumulated Depreciation - Distribution Plant	44,715							44,715
4	Accumulated Depreciation - General and Intangible Plant	-	-	-	1,035	-	-	-	1,035
5	Net Plant	(35,504)	-	(405,161)	1,035	-	-	-	(439,630)
6	Additions to Rate Base								-
7	Materials and Supplies Inventories	-	-	-	-	-	-	-	-
8	Construction Work in Progress	-	-	-	-	-	-	-	-
9	Regulatory Assets	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-
10	Deductions From Rate Base	-	-	-	-	-	-	-	-
11	Accumulated Deferred Income Taxes	421	94	-	-	556	-	-	1,071
12	Customer Deposits	-	-	-	-	-	-	-	-
13	Budget Payment Plan Balances	(165)	-	-	-	-	-	-	(165)
14	Customer Advances	-	-	-	-	-	-	-	-
15	Other Deferred Credits	-	-	-	-	-	-	-	-
16	Accumulated Investment Tax Credits	-	-	-	-	-	-	-	-
17	Operating Reserves	-	-	-	-	-	-	-	-
18	Rate Base	$ (35,248)	$ 94	$ (405,161)	$ 1,035	$ 556	$ -	$ -	$ (438,724)

Commonwealth Edison Company
Interest Synchronization Adjustment
For the Test Year Ending December 31, 2000
(Thousands)

Line No.	Description	Amount	
	(A)	(B)	
1	Distribution Plant	$ 3,645,203	(1)
2	Weighted Cost of Debt	3.97%	(2)
3	Synchronized Interest Per Staff	144,715	
4	Company Interest Expense	157,231	(3)
5	Increase (Decrease) in Interest Expense	(12,516)	
6	Increase (Decrease) in State Income Tax Expense		
7	at 7.080%	$ 886	
8	Increase (Decrease) in Federal Income Tax Expense		
9	at 35.000%	$ 4,070	
10	Sources:		
11	(1) Source: ICC Staff Ex. 17.0, Schedule 17.3, Column (D).		
12	(2) Source: ICC Staff Exhibit 12.0, Schedule 12.1.		
13	(3) Source: ComEd 4.0, Schedule C-3.4, line 3.		

Commonwealth Edison Company
Gross Revenue Conversion Factor
For the Test Year Ending December 31, 2000
(Thousands)

Line No.	Description	Rate	Per Staff With Bad Debts	Per Staff Without Bad Debts
	(A)	(B)	(C)	(D)
1	Revenues		1.000000	
2	Uncollectibles	0.71%	0.007100	
3	State Taxable Income		0.992900	1.000000
4	State Income Tax	7.08%	0.070297	0.070800
5	Federal Taxable Income		0.922603	0.929200
6	Federal Income Tax	35.00%	0.322911	0.325220
7	Operating Income		0.599692	0.603980
8	Gross Revenue Conversion Factor Per Staff		1.667523	1.655684