COMMONWEALTH OF PENNSYLVANIA

OFFICE OF SMALL BUSINESS ADVOCATE
Suite 1102, Commerce Building
300 North Second Street
Harrisburg, Pennsylvania 17101

Bernard A. Ryan, Jr.
Small Business Advocate

(717) 783-2525
(717) 783-2831 (FAX)

June 16, 1995

John G. Alford, Secretary
Pa. Public Utility Commission
Room B-18, North Office Building
P. O. Box 3265
Harrisburg, PA 17120

BTL

**Re: Pennsylvania Public Utility Commission v.
Pennsylvania Power & Light Company
Docket No. R-943271**

Dear Secretary Alford:

Enclosed for filing are the original and nine (9) copies of the Main Brief of the Office of Small Business Advocate in the above-docketed proceeding. As evidenced by the enclosed certificate of service, copies have been served on all active parties in this case.

If you have any questions, please do not hesitate to contact me.

Sincerely,

Karen Oill Moury

Karen Oill Moury
Assistant Small Business Advocate

Enclosures
cc: Hon. Robert A. Christianson
Administrative Law Judge
(2 copies with disk)

Parties of Record

ORIGINAL

RECEIVED
95 JUN 16 AM 9:48
PA. P.U.C.
INFO. CONTROL DIV.

DOCUMENT FOLDER

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION :
v. : Docket No. R-943271
PENNSYLVANIA POWER & LIGHT COMPANY :

BTL

MAIN BRIEF
OF THE
OFFICE OF SMALL BUSINESS ADVOCATE

RECEIVED
95 JUN 16 AM 9:48
PA. P.U.C.
INFO. CONTROL DIV.

Karen Oill Moury
Assistant Small Business Advocate

DOCKETED
JUN 16 1995

Office of Small Business Advocate
Suite 1102, Commerce Building
300 North Second Street
Harrisburg, PA 17101
(717) 783-2525

Dated: June 16, 1995

DOCUMENT FOLDER

ORIGINAL

TABLE OF CONTENTS

I. INTRODUCTION

On December 30, 1994, Pennsylvania Power & Light Company ("PP&L" or "Company") filed Supplement No. 50 to Tariff Electric-Pa. P.U.C. No. 200 to become effective for electric service rendered on and after February 28, 1995. By this filing, PP&L seeks to increase its rate revenues by $257,925,888, or 11.7% above its current level of rates. By order entered on January 27, 1995, pursuant to 66 Pa.C.S. §1308(d), the Commission instituted an investigation into the lawfulness, justness and reasonableness of the Company's proposed and existing rates.

The Office of Consumer Advocate ("OCA"), the Office of Small Business Advocate ("OSBA"), the PP&L Industrial Customer Alliance ("PPLICA"), the United States Department of Defense, the Central Eastern Pennsylvania Fuel Oil Dealers ("CEPFOD"), the Sierra Club, Crown American Realty Trust, the Commission on Economic Opportunity, Eric Epstein and several other individuals filed formal complaints in this proceeding. Additionally, Bethlehem Steel Corporation and the University and College Coalition ("UCC") intervened in this proceeding, and the Office of Trial Staff ("OTS") participated as a matter of statutory right. Administrative Law Judge ("ALJ") Robert Christianson presided at the evidentiary hearings held in Harrisburg. Public input hearings were held in various locations throughout PP&L's service territory. Hearings concluded and the record was closed on May 26, 1995.

The OSBA actively participated in all phases of this proceeding, presenting the direct and rebuttal testimony, along with numerous exhibits, of Robert D. Knecht. This brief addresses matters concerning cost of service and revenue allocation. The OSBA's silence with respect to other issues in this proceeding, whether raised by the Company or another party, is not intended to be and should not be interpreted as acquiescence to or endorsement of such claim.

II. SUMMARY OF ARGUMENT

The cost of service study performed by PP&L in this proceeding allocates generation and transmission demand costs on the basis of the widely-accepted twelve coincident peak method. The Company's cost study demonstrates that the small business customers in PP&L's service territory are paying substantially higher electric rates than are warranted. For instance, the GS-1 class is presently contributing a rate of return that is nearly twice the system average return.

In an effort that begins to ameliorate the existing imbalance between class rates and class costs of service, PP&L has proposed below system average increases for the GS-1 and GS-3 classes. Noting the reasonable amount of progress by those classes toward cost-based rates in this proceeding, the OSBA strongly supports PP&L's proposed revenue distribution.

Nevertheless, because of the significant disparity between rates and costs for the GS-1 class, the OSBA proposes an automatic annual adjustment mechanism. Under this mechanism, the GS-1 rates would be reduced annually so as to continue moving those rates toward cost of service without awaiting the filing of another base rate proceeding by PP&L.

Finally, in implementing a final revenue award, the ALJ and the Commission should adopt a scaleback of the Company's proposed revenue allocation that preserves a reasonable amount of the progress toward cost-based rates for the GS-1 and GS-3 classes that was inherent in the Company's original proposal.

III. ARGUMENT

A. Cost of Service

1. Allocation of Generation Demand Costs

a. Company's proposal

In performing a cost of service study for this proceeding, PP&L employed the monthly peak responsibility method, or twelve coincident peak method ("12 CP"), for the allocation of generation demand costs. This allocation method is consistent with that utilized by PP&L in its last base rate proceeding at Pa. Public Utility Commission v. Pennsylvania Power & Light Company, Docket No. R-842651, 59 Pa. P.U.C. 332, 394-398 (Order entered on April 26, 1985). As the Commission emphasized in that case:

> [C]ost of service studies are far from being an exact art and are, essentially, a useful tool for testing the reasonableness of the revenue requirement. A considerable amount of judgment is inherent in the development of cost of service studies, appropriate rate changes and the allocation of allowable revenues among the various classes of customers.

Id. at 394.[1] Recognizing the particular characteristics of PP&L's operations, the Commission expressly found the Company's "use of the twelve month coincident peak allocation methodology acceptable for cost of service allocation purposes." Id. at 398.[2] In the

---

1 *See also Pa. Public Utility Commission v. Penn Power Company, Docket No. R-870732, 67 Pa. P.U.C. 91, 166 (Order entered on May 3, 1988); Pa. Public Utility Commission v. Metropolitan Edison Company, Docket No. R-842770, 60 Pa. P.U.C. 349, 413 (Order entered on October 25, 1985).*

2 *A twelve month coincident peak allocation methodology was also recently endorsed by the Commission in Pa. Public Utility Commission v. UGI Utilities, Inc. (Electric Division, Docket No. R-00932862, 1994 Pa. P.U.C. Lexis 137, 156 (Order entered July 27, 1994). Further, in Pa. Public Utility Commission v. West Penn Power Company, Docket No. R-00942986, 1994 Pa. P.U.C.*

present case, the Company's cost of service witness, Joseph M. Kleha, explains that this method, which is based on the average of the twelve monthly coincident class demands at the time of the system monthly peak loads, most appropriately reflects the way in which production and transmission costs are incurred on PP&L's system. PP&L Stmt. No. 7 at 5.

In particular, Mr. Kleha has set forth four primary factors justifying the continued reliance on the 12 CP method. First, he points to long-term stability, noting that PP&L has used the monthly peak responsibility method in every Pennsylvania and Federal rate filing in which it has submitted cost allocation studies, and that it was found to be acceptable in PP&L's last base rate case. Second, Mr. Kleha notes that this method is consistent with the determination of PP&L's installed capacity obligation to the Pennsylvania-New Jersey-Maryland (PJM) Interconnection. Third, the monthly peak responsibility method recognizes seasonal class diversities. Fourth, according to Mr. Kleha, the 12 CP method reflects PP&L's actual system operating conditions. PP&L Stmt. No. 7 at 6-8.

b. OSBA's Position

The OSBA does not contest adoption of the 12 CP method for allocating generation demand costs in this case. As Robert D. Knecht, OSBA's witness, testifies:

Lexis 144, (Order entered on December 29, 1994 at page 101), the Commission approved a Joint Petition for Partial Settlement of Rate Proceeding which contained ECR demand factors for the rate classes based on a twelve month coincident peak method.

> The selection of the appropriate measure of peak depends on a variety of factors that are specific to each utility, including the seasonality of the peaks, the relative magnitude of the off-season monthly peaks, the maintenance requirements of the various generating facilities, and the responsibility of the utility to any larger power pool in which it jointly plans.

OSBA Stmt. No. R1 at 3. Given the justifications provided by Mr. Kleha for employing the 12 CP method, the OSBA agrees with Mr. Kleha's assertion that no compelling reason exists for departing from this methodology. Perhaps more importantly, no superior or preferable methodology has been advanced by the intervening parties in this case.

c. Positions of Other Parties

Stephen J. Baron, testifying for PPLICA, and Maurice Brubaker, testifying on behalf of Bethlehem Steel, express their preference for the use of a single coincident peak methodology, based on PP&L's winter peak during the test year, but premise their rate structure recommendations on the 12 CP methodology. PPLICA Stmt. No. 7 at 19; Bethlehem Steel Stmt. No. 1 at 8. Steven Andersen, who testifies on behalf of CEPFOD, supports the proposed 12 CP allocator. CEPFOD Stmt. No. 1 at 27. Paul M. Yarolin, the rate structure witness presented by OTS, also endorses the use of the 12 CP methodology, stating that it "best represents the costs attributable to each of the services provided by PP&L." OTS Stmt. No. SR-3 at 13.

The only cost of service witnesses in this case who seek adoption of alternative methodologies for allocating demand-related costs are Kenneth Eisdorfer for UCC, and Charles E. Johnson for OCA. Recommending the use of a single winter peak allocator, Mr. Eisdorfer has developed a revenue requirement recovery scheme based on that methodology. UCC Stmt. No. 1 at 6. Dr. Johnson proposes use of the peak and average allocation method, and recommends an alternative revenue distribution based on the results of that method. OCA Stmt. No. 3 at 9.

d. Flaws in Dr. Johnson's Peak and Average Method

Of the various methods discussed in this case for allocating generation demand costs, Dr. Johnson's is the only one that rejects the use of some type of peak-based allocator. In factoring energy considerations into the allocation of fixed demand costs, Dr. Johnson argues that if peak demand were the only consideration for capacity investment decisions, generating plant would consist solely of low capital cost combustion turbine peaking plants. Suggesting that the capital cost for a combustion turbine is about 30 to 40 percent of the capital cost of a baseload coal plant, he essentially proposes to abandon the fixed-variable scheme for classifying generation costs, and to reclassify 61.05 percent of fixed costs as "energy-related." OCA Stmt. No. 3 at 9.

Several factors compel the rejection of Dr. Johnson's proposal relating to use of this version of the peak and average allocation method. Initially, the peak and average method is inherently flawed in that it "ignore[s] the duality of the 'capital for fuel tradeoff.'" OSBA Stmt. No. R1 at 4-5. In particular, the rationale for this method focuses on low capital costs of peaking units, without acknowledging the attendant higher fuel costs, relative to baseload units. As Mr. Knecht testifies, "[g]eneration planners design an integrated system of various types of generating equipment to minimize total costs, not simply capital or fuel costs." OSBA Stmt. No. R1 at 4. In reasonably reflecting this duality of the fuel/capital tradeoff for generation planning, PP&L's fixed-variable classification scheme more appropriately captures the cost of constructing generating capacity to meet system peak demand requirements. OSBA Stmt. No. R1 at 3-5. See also PPLICA Stmt. 7-R at 6-8; Bethlehem Steel Stmt. No. 1R at 2-12.

In addition to the flaws inherent in the peak and average allocation method, Dr. Johnson's implementation of this approach is also faulty. Initially, as Mr. Baron notes, Dr. Johnson's methodology "inappropriately assigns transmission costs, which are demand-related, on an energy basis." PPLICA Stmt. 7-R at 19-20. Moreover, Dr. Johnson's methodology fails to consider the actual composition of generating plants on the PP&L system. PPLICA Stmt. No. 7-R at 4. Further, although Dr. Johnson reclassifies a substantial amount of costs from "demand-related" to "energy-related," thereby reducing demand costs assigned to the GS, GH and LP classes, his proposal does not provide for a corresponding reduction in the demand charges in the rate design for those classes. OSBA Stmt. No. R1 at 5-6.

Moreover, Mr. Kleha's rebuttal testimony resoundingly rejects Dr. Johnson's peak and average allocation proposal, noting that the Commission expressly rejected it in an earlier PP&L base rate case.

Mr. Kleha specifically criticizes Dr. Johnson's method as failing to (1) recognize the importance of the customers' load at the time of each month's peak in determining the amount and type of generating capacity installed on PP&L's system, (2) consider seasonal class diversities for the entire twelve months of the year, and (3) realize that PP&L must perform maintenance on its generation facilities during the other seven months of the year. Further, Mr. Kleha testifies the costs of generation and transmission facilities do not vary with customers' energy usage. Additionally, Mr. Kleha concludes that Dr. Johnson's proposed methodology produces unreasonable results and is incomplete. PP&L Stmt. 7-R at 8-10.

Finally, it is noteworthy that Dr. Johnson's proposed peak and average methodology in this case is not consistent with the peak and average methodology that he proposed in the recent <u>West Penn Power Company</u> case at Docket No. R-00942986. Mr. Baron explains:

> In testimony filed on behalf of the OCA in the West Penn case (ten months ago), Dr. Johnson also proposed a peak and average method. However, in that case, he utilized an equal weighting between the peak and energy (average demand) components of the allocator, following the approach in the NARUC Electric Utility Cost Allocation Manual...In this <u>PP&L case</u>, Dr. Johnson makes no mention of the NARUC Manual, nor does he utilize the "average of the two numbers: class CP (however measured) and class average demand."

PPLICA Stmt. No. 7-R at 4-5. Further, Mr. Baron has calculated that "[i]f Dr. Johnson had used the NARUC peak and average approach, which he adopted ten months ago in the West Penn case, <u>he would have allocated 3.25% more production and transmission</u>

investment to residential customers than PP&L's 12 CP method allocates." PPLICA Stmt. No. 7-R at 6.

e. Summary

For all of the reasons set forth by Witnesses Kleha, Knecht, Baron and Brubaker, Dr. Johnson's proposal for a peak and average allocation method should be rejected. In addition to the numerous problems plaguing his method, he simply has not demonstrated that it is superior to the 12 CP methodology relied upon by the Company. As noted by Mr. Kleha, "the Company's preferred 12 CP demand allocation methodology reasonably reflects the relative cost responsibilities of its customer classes and thus fairly and satisfactorily serves the rate design needs in this proceeding and should be accepted." PP&L Stmt. No. 7-R at 10-11.

2. Classification of Distribution Plant

With respect to the classification of distribution costs between demand-related and customer-related components, PP&L appropriately proposes that "certain distribution plant and associated O&M costs be split between the demand-related and customer-related classifications based on the minimum system method, as outlined in the NARUC Cost Allocation Manual." OSBA Stmt. No. R1 at 7-8. See Pa. Public Utility Commission v. Metropolitan Edison Company, Docket No. R-842770, 60 Pa. P.U.C. 349, 416 (Order entered on October 25, 1985) (Commission approved minimum grid system approach).

Witnesses Andersen and Johnson have taken issue with this approach. While Dr. Andersen would classify a subset of the particular accounts as 100% demand-related, Dr. Johnson would accept the minimum system classification, but modify the allocator used to allocate the demand portion of these costs. Both witnesses argue that the minimum system method employed by PP&L effectively double-counts the demand-carrying capabilities of the minimum system. See CEPFOD Stmt. No. 1 at 30-33; OCA Stmt. No. 3 at 14-17.

As to the witnesses' claim regarding double-counting, Mr. Knecht notes that this argument ignores the duality of the demand/customer tradeoff for distribution system costs. He explains:

> If it can be argued that a zero load system serving all customers could be built at much lower cost than PP&L's minimum system, it can equally well be argued that PP&L could serve total secondary demand at a single location at much lower cost than those costs assigned to the demand classification.

OSBA Stmt. No. R1 at 9.

Further, Mr. Kleha effectively defends the Company's reliance on the minimum system method, as follows:

> First, a minimum size distribution system, by definition, must have some load-carrying capability. The fact that the Company's minimum system has some load carrying capability provides no basis for rejecting it.
>
> Second, demand is a function of the load imposed on a utility's system by its customers and this demand and the allocators derived from it are unaffected by a "hypothetical" minimum size system study.
>
> Third, although both witnesses criticize the Company's study results, they present no alternative of their own. Rather, they engage in arbitrary and incomplete "adjustments" to the Company's method. If these witnesses

> reject the Company's study, they should present the results of an alternative method, rather than seeking to "adjust" the Company's study results.
>
> Fourth, both parties fail to consider the fact that PP&L has allocated its primary voltage-related distribution system costs solely on the basis of demand even though the primary-voltage system undoubtedly has a customer-related cost component which could offset any perceived overstatement of the customer-related cost component associated with the secondary voltage-related distribution system.

PP&L Stmt. No. 7-R at 23-24.

Additionally, Dr. Johnson's adjustments contain numerous methodological errors, resulting in an unreasonable split of distribution costs into demand and customer components. While normally the extreme bounds of the cost split are from 100 percent demand-related to 100 percent customer-related, Dr. Johnson's proposal would result in a negative customer weight and a demand weight exceeding 100 percent for all secondary distribution cost components except service drops. As Mr. Knecht has calculated for the RS class, Dr. Johnson's method implies an approximate customer component of <u>negative</u> 30 percent, and a demand component of 130 percent." OSBA Stmt. No. R1 at 14-16; OSBA Exhibit R2.

In the 1985 <u>Met-Ed</u> decision, the Commission expressly supported the "use of a customer component in the allocation of distribution plant costs." 60 Pa. P.U.C. at 416. Further, Professor Bonbright's <u>Principles of Public Utility Rates</u> specifically rejects assignment of these costs to the demand component and confirms the wide acceptance of minimum system/zero intercept methods. See OSBA Stmt. R1 at 12-13 and OSBA Exhibit R1; Tr. 1318-1319. Since the proposals of Witnesses Andersen and Johnson relating to the classification of distribution costs include no customer component, they should be rejected. PP&L's minimum system approach, which is consistent with the NARUC manual, should "be adopted as the most reasonable of methodologies posited in these proceedings." OSBA Stmt. R1 at 16.

3. Results of Company's Cost Allocation Study

The results of the Company's cost of service study employing the 12 CP methodology are summarized at PP&L Exhibit OGK-3. That exhibit shows that at present rates, the GS-1 class provides a 14.41% rate of return, which is 1.97 times, or nearly twice, the system average return of 7.31%. Furthermore, evidence submitted by Mr. Knecht comparing the monthly bills paid by average RS and GS-1 customers shows that even with PP&L's proposal for a substantially larger increase to the RS class, the GS-1 service is some 20% more expensive than RS service. OSBA Exhibit 1. Noting that no cost justification for this difference exists and that in fact the GS-1 allocated cost per kwh is lower than that of the residential class (OSBA Exhibit 2), Mr. Knecht observes that "[t]he higher rates combined with the lower costs produce an indexed rate of return for the GS-1 class under present rates of 197%, the highest of any of the major rate classes." OSBA Stmt. No. 1 at 3-4. Also, the GS-3 class currently exhibits a return of 9.93% which is roughly 1.36 times the system average return, the second highest of any of the major classes. PP&L Exhibit OGK-3; OSBA Stmt. No. 1 at 5.

Calculations of cross-subsidization which are presented in UCC Cross-Examination No. Exhibit 6 further demonstrate the inequities inherent in the present rate structure. As UCC Cross-Examination No. Exhibit 6 shows, $38,874,000, or over twenty-five percent, of the total rate revenues presently collected from GS-1 customers actually go to subsidize other rate classes, consisting of primarily the RS and LP-5 classes. <u>See</u> PP&L Attachment IV-C, page 6; Tr. 735. Additionally, $50,584,000, or over 10 percent of the revenues currently collected from the GS-3 class provides a subsidy to other rate classes. <u>See</u> PP&L Attachment IV-C, page 9 (1994 Rate Revenue Under Present Rate).

Clearly, all of this cost data confirms the following findings that were expressed in the November 1994 report prepared by PP&L's Social Initiatives Task Force:

> The small business customer (e.g., mom-and-pop stores) is the forgotten customer at PP&L. There are nearly 120,000 small general service customers, and as a group, they pay the highest electric rates. In addition, they receive the least amount of customer service and support from the company. These customers often play a role in maintaining the viability of the neighborhoods where they are located.

OTS Cross Examination Exhibit No. 16, Attachment 1, page 10.

B. Revenue Distribution

1. Company's Proposal

In an effort which begins to rectify the historical problem of small businesses paying much higher electric rates than their costs warrant, PP&L's rate design witness, Oliver G. Kasper, proposes to allocate the Company's requested revenue increase in a manner designed to move these classes consisting of small business customers toward the system average return. In particular, PP&L proposes below system average increases for the GS-1 and GS-3 classes of 3.89% and 6.72% respectively. Approval of PP&L's proposed revenue allocation would result in improved relative rates of return for both classes. As PP&L Exhibit OGK-3 shows, the proposed rate of return for the GS-1 class is 15.64%, which is about one and a half times the proposed system return of 10.17%. For the GS-3 class, PP&L has proposed an 11.73% rate of return, which is about 1.15 times the proposed system return. Thus, even with below system average increases for the GS-1 and GS-3 classes, the customers receiving service under those rate schedules would continue to pay more than their fair share of the revenue burden.

2. OSBA's Proposal

While cost of service results alone would support a substantial decrease in rates for the GS-1 class (-14.32%) and an extremely minimal increase for the GS-3 class (0.84%), Mr. Kasper applied other rate design principles, including gradualism, in developing a proposed revenue allocation. PP&L Stmt. 8 at 6; Exhibit OGK-3; Tr. 741-742. Recognizing that further progress by these classes toward cost-based rates in this proceeding is constrained by the principle of gradualism, the OSBA has not proposed an alternative revenue distribution. We therefore urge adoption of Mr. Kasper's recommended allocation of the proposed revenue increase.

Because, however, the GS-1 class is so far out of line with costs, Mr. Knecht has suggested an automatic adjustment mechanism for reducing rates to the GS-1 class on each anniversary of the effective date of the newly approved rates. See OSBA Stmt. No. 1 at 5-7. In objecting to Mr. Knecht's proposal for an automatic adjustment in rates, Dr. Johnson argues that no cost "study done today can be expected to represent the allocation of costs accurately over the next ten years." OCA Stmt. No. 3A at 9.

This argument mischaracterizes Mr. Knecht's proposal, which does not provide for an automatic rate adjustment for a period of ten years, but rather recommends that such a mechanism be employed until PP&L's next base rate proceeding. As Mr. Knecht testifies, if PP&L were expected to file for rate relief in the next year or two, and thereby continue the progress initiated in this case of moving the rates for GS-1 closer to costs, he would conclude that the progress sought in this case is sufficient. OSBA Stmt. No. 1 at 5. Noting, however, PP&L's general plan for another base rate proceeding in three years, combined with its front-loading of certain costs into its revenue requirement for the express purpose of deferring future rate proceeding, Mr. Knecht believes that his proposal would allow for modest continued progress until the next full base rate proceeding. OSBA Stmt. No. 1 at 6-7. With or without an annual rate adjustment mechanism, the cost study adopted in this proceeding will represent the allocation of costs until PP&L's next base rate case. However, without this mechanism, the GS-1 class is at risk of continuing to provide substantial subsidies over a very long period of time, such as the ten-year period that elapsed since the last base rate case filed by PP&L.

Mr. Kasper objects to the automatic rate adjustment proposal by simply stating that Mr. Knecht has not provided the needed support. PP&L Stmt. 8-R at 25. Since Mr. Kasper has not identified what support other than the undisputed cost data for GS-1 relied upon by Mr. Knecht is necessary, and he has not provided any specific reasons for rejecting this proposal, the OSBA urges the ALJ to direct that the Company implement this automatic adjustment mechanism for the GS-1 rates as outlined in Mr. Knecht's testimony.

3. OCA's Proposal

The only proposal by an intervening party that would increase the combined revenue responsibility of Rate Schedules GS-1 and GS-3, over the levels of rate revenues sought to be recovered from those classes by the Company, is that of OCA's witness, Dr. Johnson. <u>See</u> OCA Stmt. No. 3 at 21 and Exhibit CEJ-1, Schedule 2, Page 4 of 4. Since Dr. Johnson's proposed revenue allocation is premised upon a cost of service study that has been extensively refuted by Mr. Kleha for PP&L, Mr. Baron on behalf of PPLICA, Mr. Brubaker for Bethlehem Steel, Mr. Yarolin for OTS, Mr. Eisdorfer on behalf of UCC, and Mr. Knecht for OSBA, his recommendation should be afforded no consideration. As Mr. Knecht notes, "[a]ny one of the changes that Dr. Johnson proposes to PP&L's cost allocation study creates cost allocation errors significant enough to reject his proposed allocation of the revenue requirement." OSBA Stmt. R1 at 27. Thus, rejection of any aspect of Dr. Johnson's cost of service study invalidates his proposed revenue allocation.

Further, although Dr. Johnson's study allocates fewer costs to the GS-1 class than does the Company's study, resulting in a class rate of return that is more than twice the system average return, his revenue allocation proposal assigns a higher increase (5.9%) to the GS-1 class than is proposed by the Company (3.9%). Explaining during cross-examination that he simply calculated the necessary revenue from the GS-1 class as a residual, Dr. Johnson acknowledged that he did not rely on the relative costs of service produced from his own study for setting rates for that class. Tr. 1389. In view of this arbitrary assignment of a revenue requirement to the GS-1 class, the OSBA urges rejection of his proposal for a revenue distribution among the customer classes. See OSBA Stmt. No. R1 at 27-28.

Moreover, despite the results of Dr. Johnson's study showing the GS-3 class at a relative rate of return of 118.67%, he has proposed an 11% increase, compared to the Company's 6.87%, which would amount to a $55.8 million increase to that class, compared to the Company's proposed $34.1 million increase. Indeed, at full rate relief, Dr. Johnson seeks to shift approximately $32 million in revenue responsibility away from the RS class. Of that amount, he proposes to have roughly $25 million recovered from the GS-1 and GS-3 classes, the very customers that are already providing substantial subsidies to the residential classes and have been recently identified by the Company's internal task force as the "forgotten customer at PP&L." OTS Cross Examination Exhibit No. 16, Attachment 1, page 10.

4. PPLICA's Proposal

The OSBA notes that PPLICA's revenue allocation proposal presented by Mr. Baron assigns a somewhat larger increase to the GS-3 class than is proposed by the Company. Nevertheless, his proposal imposes no increase on the GS-1 class. Therefore, the combined revenue requirement he seeks to have recovered from the GS-1 and GS-3 classes is actually lower than the amount the Company seeks to collect from those classes. Recognizing that we have not contested this aspect of Mr. Baron's proposal, we note that if Mr. Baron's overall revenue allocation proposal is adopted, the Company could be directed to implement increases to both classes that are more in line with the proportions originally proposed by the Company. In that manner, the combined revenue requirements proposed by Mr. Baron for those two classes could be achieved. The GS-1 class, however, would be contributing to the revenue increase, and the increase to the GS-3 class would be moderated consistent with the Company's original proposal.

C. Allocation of a Reduced Revenue Deficiency

1. Proportional Scaleback

Assuming that PP&L's revenue deficiency is lower than the proposed level of $262 million, and that its proposed revenue allocation is adopted, an issue arises as to how the lower deficiency should be allocated among the classes. While a proportional scaleback is a traditional method, the OSBA has proposed an alternative which Mr. Knecht refers to as a "weighted scaleback" method. The rationale underlying this alternative is Mr. Knecht's testimony that particularly in the event of a significant reduction in the revenue deficiency, a simple proportional scaleback of the Company's proposed revenue allocation would fail to move the classes as close to cost-based rates[3] as they would have moved under the Company's original proposal. OSBA Stmt. No. 1 at 8.

During cross-examination, Mr. Kasper testified that the amount of progress toward cost-based class rates that would occur under his proposed revenue distribution should be a factor in determining the appropriate scaleback method to be employed. Tr. 742. He also agreed that a similar amount of progress should occur at whatever revenue award is finally authorized. Tr. 743. Additionally, Mr. Kasper agreed that a simple proportional scaleback of the proposed rates would not necessarily result in the same amount of progress toward cost-based rates for all customer classes as he has proposed. Tr. 743. Despite this testimony, Mr. Kasper now advocates use of proportional scaleback. PP&L Stmt. 8-R at 5.

---

[3] *The OSBA, for purposes of this argument, is equating movement in the class indexed rate of return toward 1.00 with movement toward cost-based rates. We note, however, that Mr. Knecht has also referred to a revenue-to-cost ratio that he believes is a more neutral and objective measure of progress toward cost-based rates. In prior cases, the OSBA has relied upon Mr. Knecht's preferred revenue-to-cost ratio, as well as other measures of progress such as one that examines the absolute growth or reduction of dollar subsidies, to argue for a certain revenue distribution. While we continue to believe that the relative rate of return measure has drawbacks which sometimes result in an indication of more progress toward cost-based rates than truly occurs, we are opting in this case to refrain from that argument in hopes of simplifying our position on the appropriate scaleback method that should be employed.*

The Company originally proposed a revenue allocation that would move the GS-1 class from an indexed rate of return of 197.13% at present rates to an indexed rate of return of 153.79% at proposed rates. Similarly, the Company's proposed revenue distribution would move the GS-3 class from an indexed rate of return of 135.84% at present rates to an indexed rate of return of 115.34% at proposed rates. Exhibit OGK-3. While that amount of progress by the GS-1 and GS-3 classes toward cost-based rates appears reasonable, that level of progress will simply not occur if the Company's revenue distribution is proportionally scaled back to reflect a lower revenue deficiency.

To illustrate this point, Mr. Knecht has prepared a simple two-class hypothetical example, which is included as Exhibit 3 to OSBA Stmt. No. 1. For ease of reference, a copy of OSBA Exhibit 3 is appended to this brief as part of Appendix A. A review of OSBA Exhibit 3 demonstrates that a proportional scaleback reduces the amount of progress that individual classes make toward cost-based rates.

In Mr. Knecht's example depicted in OSBA Exhibit 3, a utility requests a $20 million, or 10%, increase. The $20 million is proposed to be allocated as follows: $15 million to Residential and $5 million to Industrial. Approval of the proposed revenue allocation at that level of relief would result in the Residential class moving from an indexed return of 0.640 to 0.733, and would move the indexed return for Industrial class from 1.6 to 1.444. If a $5 million, or 2.5%, increase were ultimately approved, and a proportional scaleback from the utility's proposed revenue allocation were implemented, the Residential indexed rate of return would move from 0.640 to 0.680, while the Industrial indexed rate of return would move from 1.600 to 1.533. Obviously, neither class under this scenario would move as close toward a relative rate of return of 1.00 as was originally envisioned by the utility.

2. Constant Differential Scaleback

In order to achieve a similar amount of progress toward cost-based rates as was originally proposed by the utility, it would be necessary to use another scaleback approach. Mr. Knecht identified such a method as a "constant differential approach, wherein the difference between the class rate of return and the system average rate of return in the approved deficiency allocation is modified by the change in the overall allowed increase." OSBA Stmt. No. 1 at 9. Specifically, this method would use the approved revenue allocation as a starting point and then maintain that differential between the system increase and each class increase.

So in Mr. Knecht's hypothetical example set forth in Exhibit 3, the utility's proposed revenue allocation is approved but the final revenue award is reduced from an overall increase of 10 percent to an overall increase of 2.5 percent. Under a proportional scaleback, a reduction in the system increase to 2.5 percent would result in a 3.8 percent increase to the Residential class. A constant differential approach, however, would assign a 7.5 percent increase to the Residential class, maintaining the five percentage points between the original proposed system increase of

10 percent and the original proposed Residential class increase of 15 percent.

As OSBA Exhibit 3 demonstrates, implementation of the constant differential approach in Mr. Knecht's example would result in approximately the same amount of movement in the indexed rate of return for both the Residential and Industrial classes as would have occurred under the utility's original proposal. Specifically, in the example, use of the constant differential method to allocate a significantly reduced revenue deficiency would move the Residential class indexed rate of return from 0.640 to 0.735 and would move the Industrial class indexed rate of return from 1.600 to 1.442. For both classes, the indexed rate of return resulting from the implementation of the rate increase would be almost identical to the indexed rate of return originally proposed by the Company.

3. Weighted Scaleback

Recognizing that reliance on the constant differential approach in the present case could easily result in rate decreases for particular classes, including GS-1 and GS-3, which may not be viewed favorably by the Commission, Mr. Knecht has also developed a "weighted scaleback" approach. Essentially, this approach combines the concepts of a proportional scaleback and the constant differential method. To illustrate how this "weighted scaleback" approach would work at different levels of revenue deficiency, Mr. Knecht has prepared OSBA Exhibit 4, which is attached to this brief at Appendix A. As shown on that exhibit, the "weighted scaleback" method requires a calculation of the class increases necessary to implement both a proportional scaleback and a constant differential scaleback. Then, a weighting needs to be applied to each set of results to arrive at class increases that consider both approaches.

On Exhibit 4, Mr. Knecht sets forth the class increases that would result under the proportional scaleback, the constant differential scaleback and the weighted scaleback at three different levels of rate relief. Focusing particularly on the GS-3 class at a revenue increase of approximately half of what PP&L has proposed, a proportional scaleback from the Company's recommended revenue distribution would result in an increase of 3.4%, while the use of a constant differential would produce a 0.8% increase. Under Mr. Knecht's weighted scaleback method, the GS-3 class would receive a 2.1% increase. While the weighted scaleback method relies only partially on the results of the constant differential method, and would therefore not produce the level of progress toward cost-based rates as was originally proposed by the Company, use of the weighted scaleback approach is superior to the proportional scaleback in that it would at least achieve a greater portion of the improvement in the relative rates of the various classes that was initially sought by the Company.

No rebuttal testimony was filed by the other cost of service/rate design witnesses in this case to refute any of the claims made by Mr. Knecht with respect to his conclusions about the reduced level of progress that occurs toward cost-based rates from employing the proportional scaleback method. The extent of the rebuttal testimony concerning his weighted scaleback proposal was that of Mr. Kasper, who simply referred to it as an example of a proposal by an intervenor witness that is "designed to benefit a specific class at the expense of the other classes." PP&L Stmt. No. 8-R at 5. While Mr. Knecht's proposal would clearly be more beneficial to the GS-1 and GS-3 classes, as well as LP-4 and LPEP, than would implementation of a proportional scaleback, the result that he was expressly seeking is one that more closely resembles the movement toward cost-based rates inherent in the Company's original proposal, while still having all classes share in the revenue increase.

Given Mr. Kasper's testimony that the amount of progress toward cost-based class rates originally sought by the Company should be considered in determining the appropriate scaleback and that less progress toward cost-based rates would occur under a proportional scaleback than was inherent in the Company's original proposal, an alternative scaleback approach is appropriate. Since Mr. Knecht's weighted scaleback proposal would achieve a closer resemblance to the level of progress originally envisioned by the Company, adoption of the weighted scaleback proposal is warranted.

As to Mr. Kasper's desire to reflect gradualism by maintaining an upper limit for any class of 1.5 times the approved system average increase (Tr. 772-773), this constraint is unnecessary if the overall increase is substantially reduced from the level requested by PP&L. As Mr. Knecht testifies:

> The absolute magnitude of the rate increase is what really matters to customers, not the increase relative to other customer classes. It makes no sense to me to say that, a 15.3 percent increase to the RS class does not violate the gradualism principle when the system average increase is 11.7 percent, but that a 4 percent increase does violate gradualism when the system increase is 2 percent. The 1.5 factor is reasonable for a system increase on the order of 11 or 12 percent. If that overall increase is substantially reduced, the 1.5 factor is no longer appropriate.

OSBA Stmt. No. 1 at 11.

While Mr. Knecht's weighted scaleback proposal would result in increases to some classes that exceed 1.5 times the system increase, that would occur only if there are very substantial reductions in the revenue deficiency, and even then, it would occur only minimally. Specifically, when the revenue deficiency is reduced by twenty-five percent, none of the class increases would exceed 1.5 times the system increase. At a fifty percent reduction in the revenue deficiency, the RTS increase would be roughly 1.7 times the system increase and the increase for GS(R) would be about 1.6 times the system increase. Even at a seventy-five percent reduction in the revenue deficiency, the increase to the RS class would be about 1.55 times the system increase, and the increases to the RTS and GH(R) classes would be less than twice the system increase.

Although Mr. Knecht sets forth the results of the weighted scaleback approach at only three different levels of rate relief, his formulas are included in Exhibit 4 and could readily be applied to any level of revenue deficiency. Further, Mr. Knecht provides guidance in his direct and rebuttal testimony for implementing his scaleback proposal at varying levels of rate relief. See OSBA Stmt. No. 1 at 11-12; OSBA Stmt. No. R1 at 30-32.

Moreover, a weighted scaleback approach could be employed for any revenue allocation that is ultimately approved by the Commission. Indeed, Mr. Knecht identified the difficulty with employing a proportional scaleback of Mr. Baron's revenue allocation proposal as it would impact upon the interruptible class of customers:

> If a proportional scaleback is used, particularly for a large reduction in the deficiency, and the interruptible customers are treated as a separate class, the effective interruptible discount for firm service will rise back to its current unacceptably high levels.

OSBA Stmt. No. R1 at 29-30. Thus, regardless of the revenue allocation that is finally adopted by the Commission, Mr. Knecht's weighted scaleback method should be implemented so as to retain some reasonable level of progress toward cost-based rates that is inherent in that revenue allocation proposal.

In the event of a very small revenue award in this case, Mr. Knecht notes that any scaleback method that seeks to have all classes contribute to the increase "will produce very little variation in rate increases amongst the classes and very little progress toward cost based rates." OSBA Stmt. No. R1 at 31. Under that circumstance, he states:

> I strongly recommend that rate declines for some classes be found to be an acceptable assignment of the deficiency. Base rate cases are extraordinarily expensive and time

> consuming, and can be few and far between. The small business classes under present rates are currently subsidizing many of the other classes. Assigning very similar increases to all of the classes at this time simply perpetuates this inequity.

OSBA Stmt. No. R1 at 31. While Mr. Knecht does not recommend departure from this weighted scaleback proposal in this situation, he does recommend that greater weight be given to the constant percent differential method. A formula for implementing this proposal is set forth in his rebuttal testimony. OSBA Stmt. No. R1 at 31-33.

D. Allocation of a Negative Revenue Deficiency

In view of OCA's proposal in this case for a reduction in PP&L's revenue requirements, the ALJ requested that the rate design witnesses provide some guidance on how a negative revenue deficiency should be allocated among the classes (Tr. 1006). In response to that request, Mr. Knecht set forth a formula for determining an allocation that would maintain some reasonable amount of progress toward cost-based rates. See OSBA Stmt. No. R1 at 33-36. From the OSBA's perspective, it is important to use this opportunity of a rate case to make some movement of class rates toward class costs even if no rate increase is awarded. Where a cost of service study has been performed that shows the GS-1 and GS-3 classes currently paying rates that are far in excess of the costs they impose on the system, it would be inequitable to ignore those results and thereby perpetuate the existing imbalance.

IV. CONCLUSION

Based upon the foregoing, the Office of Small Business Advocate respectfully requests that the ALJ and the Commission (1) approve the revenue distribution proposed by the Company, (2) direct the Company to implement an automatic rate adjustment mechanism for the GS-1 rate schedule as outlined in the testimony of Robert D. Knecht for the OSBA, and (3) order a scaleback of the proposed revenue distribution, to reflect the final revenue award, that maintains some reasonable amount of progress toward cost-based rates for the GS-1 and GS-3 rate classes that is inherent in the Company's original proposal.

Respectfully submitted,

Karen Oill Moury

Karen Oill Moury
Assistant Small Business Advocate

Date: June 16, 1995

APPENDIX A

EXHIBIT 3

ALTERNATIVE DEFICIENCY ALLOCATION METHODS
TWO-CLASS EXAMPLE

	Present Rates			Proposed Rates		
	Residential	Industrial	Total	Residential	Industrial	Total
Base Proposal						
Revenues	100.0	100.0	200.0	115.0	105.0	220.0
Percent Increase				15.0%	5.0%	10.0%
Deficiency Allocation				15.0	5.0	20.0
Allocated Rate Base	500.0	300.0	800.0	500.0	300.0	800.0
Allocated O&M Costs	60.0	40.0	100.0	60.0	40.0	100.0
Rate of Return	8.0%	20.0%	12.5%	11.0%	21.7%	15.0%
Indexed Rate of Return	0.640	1.600		0.733	1.444	
Revenue-Cost Ratio	0.816	1.290		0.852	1.235	
Proportional Scaleback						
Present Revenues	100.0	100.0	200.0	103.8	101.3	205.0
Percent Increase				3.8%	1.3%	2.5%
Deficiency Allocation				3.8	1.3	5.0
Allocated Rate Base	475.0	285.0	760.0	475.0	285.0	760.0
Allocated O&M Costs	57.0	38.0	95.0	57.0	38.0	95.0
Rate of Return	9.1%	21.8%	13.8%	9.8%	22.2%	14.5%
Indexed Rate of Return	0.655	1.575		0.680	1.533	
Revenue-Cost Ratio	0.815	1.292		0.825	1.278	
Constant Differential						
Present Revenues	100.0	100.0	200.0	107.5	97.5	205.0
Percent Increase				7.5%	-2.5%	2.5%
Deficiency Allocation				7.5	(2.5)	5.0
Allocated Rate Base	475.0	285.0	760.0	475.0	285.0	760.0
Allocated O&M Costs	57.0	38.0	95.0	57.0	38.0	95.0
Rate of Return	9.1%	21.8%	13.8%	10.6%	20.9%	14.5%
Indexed Rate of Return	0.655	1.575		0.735	1.442	
Revenue-Cost Ratio	0.815	1.292		0.855	1.230	

Note: For simplicity, income taxes are included in the return component.

EXHIBIT 4
ALTERNATIVE DEFICIENCY ALLOCATION METHODS FOR PP&L

	PP&L PROPOSAL			25% DEFICIENCY REDUCTION			50% DEFICIENCY REDUCTION			75% DEFICIENCY REDUCTION		
DEFICIENCIES												
Class	Present Revenues	Proposed Revenues	Deficiency	Proportional Scaleback	Constant Differential	Weighted Scaleback	Proportional Scaleback	Constant Differential	Weighted Scaleback	Proportional Scaleback	Constant Differential	Weighted Scaleback
RS	887.1	1,022.7	135.6	101.7	109.4	107.5	67.8	83.2	75.5	33.9	57.0	39.7
RTS	19.8	23.2	3.4	2.6	2.9	2.8	1.7	2.3	2.0	0.9	1.7	1.1
GS-1	162.2	168.5	6.3	4.7	1.5	2.3	3.2	(3.3)	(0.1)	1.6	(8.1)	(0.8)
GS-3	507.2	541.3	34.1	25.6	19.1	20.7	17.0	4.1	10.6	8.5	(10.8)	3.7
LP-4	273.4	301.1	27.8	20.8	19.7	20.0	13.9	11.6	12.8	6.9	3.6	6.1
LP-5	259.6	299.7	40.1	30.1	32.4	31.9	20.1	24.8	22.4	10.0	17.1	11.8
LPEP	8.4	8.9	0.5	0.3	0.2	0.2	0.2	(0.0)	0.1	0.1	(0.3)	0.0
SL/AL	21.2	24.2	3.0	2.3	2.4	2.4	1.5	1.8	1.6	0.8	1.1	0.9
GH(R)	43.6	50.7	7.0	5.3	5.8	5.6	3.5	4.5	4.0	1.8	3.2	2.1
Sub-Total	2,182.4	2,440.3	257.9	193.4	193.4	193.4	128.9	128.9	128.9	64.5	64.5	64.5
ISA	20.4	20.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Standby	1.1	1.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Stystem	2,204.0	2,462.0	257.9	193.5	193.5	193.5	129.0	129.0	129.0	64.5	64.5	64.5
PERCENT CHANGES IN RATES												
RS	887.1	1,022.7	15.3%	11.5%	12.3%	12.1%	7.6%	9.4%	8.5%	3.8%	6.4%	4.5%
RTS	19.8	23.2	17.4%	13.0%	14.4%	14.1%	8.7%	11.5%	10.1%	4.3%	8.5%	5.4%
GS-1	162.2	168.5	3.9%	2.9%	0.9%	1.4%	1.9%	-2.0%	-0.0%	1.0%	-5.0%	-0.5%
GS-3	507.2	541.3	6.7%	5.0%	3.8%	4.1%	3.4%	0.8%	2.1%	1.7%	-2.1%	0.7%
LP-4	273.4	301.1	10.2%	7.6%	7.2%	7.3%	5.1%	4.3%	4.7%	2.5%	1.3%	2.2%
LP-5	259.6	299.7	15.4%	11.6%	12.5%	12.3%	7.7%	9.5%	8.6%	3.9%	6.6%	4.5%
LPEP	8.4	8.9	5.5%	4.1%	2.6%	2.9%	2.8%	-0.4%	1.2%	1.4%	-3.4%	0.2%
SL/AL	21.2	24.2	14.3%	10.7%	11.3%	11.2%	7.1%	8.4%	7.8%	3.6%	5.4%	4.0%
GH(R)	43.6	50.7	16.1%	12.1%	13.2%	12.9%	8.1%	10.2%	9.2%	4.0%	7.3%	4.8%
Sub-Total	2,182.4	2,440.3	11.8%	8.9%	8.9%	8.9%	5.9%	5.9%	5.9%	3.0%	3.0%	3.0%
ISA	20.4	20.5	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%
Standby	1.1	1.2	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%
Stystem	2,204.0	2,462.0	11.7%	8.8%	8.8%	8.8%	5.9%	5.9%	5.9%	2.9%	2.9%	2.9%

Notes:

1) Proportional Scaleback: Original class deficiency is reduced by the percentage decline in the overall deficiency.

2) Constant Differential: Original proposed percentage increase in rates is reduced by the differential between the original system percentage increase and the reved percentage system increase.

3) Weighted Scaleback: w * (proportional scaleback deficiency) + (1-w)*(constant differential deficiency), where w = (1-revised deficiency)/(original deficiency)

4) ISA and Standby classes are assumed to exhibit no change in the proposed deficiency.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	Docket No. R-943271
PENNSYLVANIA POWER & LIGHT COMPANY	:	

CERTIFICATE OF SERVICE

I certify that I am today serving copies of the main brief on behalf of the Office of Small Business Advocate in the manner indicated upon the persons addressed below:

Hon. Robert A. Christianson
Administrative Law Judge
Pa. Public Utility Commission
P.O. Box 3265
Harrisburg, PA 17120
(hand delivered 6/16)

Paul E. Russell, Esquire
Associate General Counsel
Pennsylvania Power & Light Company
Two North Ninth Street
Allentown, PA 18101-1179
(overnight mail 6/15)

Thomas P. Gadsden, Esquire
Anthony C. DeCusatis, Esquire
David B. MacGregor, Esquire
Morgan, Lewis & Bockius
2000 One Logan Square
Philadelphia, PA 19103
(overnight mail 6/15)

Christopher J. Barr, Esquire
Morgan, Lewis & Bockius
1800 M Street N.W.
Washington, D.C. 20026-5869
(overnight mail 6/15)

Johnnie E. Simms, Esquire
Kenneth L. Mickens, Esquire
Stephen E. Gorka, Esquire
Office of Trial Staff
Pa. Public Utility Commission
P.O. Box 3265
Harrisburg, PA 17105
(hand delivered 6/16)

Tanya McCloskey, Esquire
Mary C. Kenney, Esquire
Gicine P. Brignola, Esquire
Office of Consumer Advocate
1425 Strawberry Square
Harrisburg, PA 17120
(hand delivered 6/16)

David M. Kleppinger, Esquire
McNees, Wallace & Nurick
100 Pine Street
P.O. Box 1166
Harrisburg, PA 17108-1166
(hand delivered 6/16)

Joan O. Brandeis, Esquire
Schnader, Harrison, Segal and Lewis
1600 Market Street, Suite 3600
Philadelphia, PA 19103-4252
(overnight mail 6/15)

Stephen J. Selden, Esquire
Bethlehem Steel Corporation
Eighth and Eaton Avenues
Bethlehem, PA 18016
(overnight mail 6/15)

David A. McCormick, Esquire
Regulatory Law Office (U-3848)
Department of the Army
901 North Stuart St. Room 400
Arlington, VA 22203-1837
(overnight mail 6/15)

DOCKETED
JUN 16 1995

DOCUMENT FOLDER

RECEIVED
95 JUN 16 AM 9:48
PA. P.U.C.
SEC. CONTROL DIV.

Alan J. Barak, Esquire
Mid-Atlantic Energy Project
Widener Energy Law Clinic
3700 Vartan Way
Harrisburg, PA 17110-9450
(hand delivered 6/16)

Wayne M. Thomas, Esquire
1101 Market Street, 24th Floor
Philadelphia, PA 19107
(overnight mail 6/15)

James P. Melia, Esquire
Daniel P. Delaney, Esquire
Kirkpatrick & Lockhart
240 North Third Street
Harrisburg, PA 17101-1503
(hand delivered 6/16)

D. Jane Drennan, Esquire
Drennan & Associates
1216 16th Street, N.W.
Washington, D.C. 20036
(overnight mail 6/15)

Kenneth Zielonis, Esquire
Stevens & Lee
Suite 310, 208 N. Third Street
P. O. Box 12090
Harrisburg, PA 17108
(hand delivered 6/16)

Mr. Craig Kuennen
Comm. on Economic Opportunity
211 S. Main Street
Wilkes Barre, PA 18701-1596
(overnight mail 6/15)

Robert P. Haynes, III, Esquire
Mette, Evans & Woodside
3401 North Front Street
P. O. Box 5950
Harrisburg, PA 17110-0950
(hand delivered 6/16)

Christopher S. Underhill, Esq.
Hartman Underhill & Brubaker
221 East Chestnut Street
Lancaster, PA 17602
(first class mail 6/15)

Mr. Eric Epstein
2308 Brandywine Drive
Harrisburg, PA 17110
(first class mail 6/15)

Karen Oill Moury

Karen Oill Moury
Assistant Small Business Advocate

Date: June 16, 1995

MID-ATLANTIC ENERGY PROJECT

A Project of the Pace University School of Law
Center for Environmental Legal Studies

Sender's Address:

☐ New York Office
Pace University School of Law
78 North Broadway, White Plains, NY 106
914/422-4227 ▪ 914/422-4180 FAX

▪ Pennsylvania Office
Widener Energy Law Clinic
3700 Vartan Way
Harrisburg, Pennsylvania 17110-9450
717/541-1967 ▪ 717/541-1970 FAX

☐ New Jersey Office
129 Washington Street
Hoboken, New Jersey 07030
201/792-5911 ▪ 201/792-9531 FAX

June 16, 1995

John J. Alford, Secretary
PA Public Utility Commission
Room G-23, North Office Building
P.O. Box 3265
Harrisburg, PA 17105-3265

RE: Pennsylvania Public Utility Commission v. Pennsylvania Power & Light Co.
Docket No. R-00943271
Brief of Sierra Club

Dear Secretary Alford:

Enclosed please find the original and nine (9) copies of the Brief of Sierra Club. All parties of record have been duly served as evidenced by the attached Certificate of Service.

Please date-stamp a copy of this transmittal letter, the cover of our brief, and the cover of our Certificate of Service for our files and kindly return in the envelope provided.

Very truly yours,

Alan J. Barak
Mid-Atlantic Energy Project
V/717-541-1967
F/717-541-1970

AJB/mlm
Enclosures

cc: Honorable Robert A. Christianson
Parties of Record

\ppl1\scbrief.ltr

COMMONWEALTH OF PENNSYLVANIA
BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-000943271
	)	
Pennsylvania Power & Light Co. (General rate increase request)	)	

SIERRA CLUB'S BRIEF

Alan J. Barak,
Attorney for Sierra Club

Alan J. Barak
Mid-Atlantic Energy Project
Widener Energy Law Clinic
3700 Vartan Way
Harrisburg PA 17110

Daniel W. Rosenblum, Director,
Mid-Atlantic Energy Project
Of Counsel

717/541-1967 (voice)
717/541-1970 (fax)

Dated: June 16, 1995

COMMONWEALTH OF PENNSYLVANIA
BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-000943271
	)	
Pennsylvania Power & Light Co. (General rate increase request)	)	

SIERRA CLUB'S BRIEF

TABLE OF CONTENTS

COMMONWEALTH OF PENNSYLVANIA
BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-000943271
	)	
Pennsylvania Power & Light Co.	)	
(General rate increase request)	)	

SIERRA CLUB'S BRIEF

SUMMARY

Two themes run through Sierra Club's brief -- customer choice for cost effective demand side services and placing DSM and renewables on a fair, level playing field with more traditional supply side services.

This Brief addresses the following matters: background of the case, including a summary of the rate filing, the OCA's Complaint, the parties' complaints, Sierra Club and its interests, and the history of the case; Sierra Club's positions on cost of service issues and rate design; the status of Sierra Club's discovery; and the relief Sierra Club has requested.

HISTORY OF THE CASE

1 THE RATE FILING

On December 30, 1994, Pennsylvania Power & Light Company ("PP&L" or "the Company") filed Tariff Supplement No. 50 to Tariff Electric - Pa. P.U.C. No. 200, setting forth proposed changes and increases in base rates ("PP&L Rate Filing") of $261 million, or about 11.7%.[1] The Commission assigned the matter Docket No. R-00943271.

2 THE OCA COMPLAINT

On January 23, 1995, the Office of Consumer Advocate ("OCA"), Irwin A. Popowsky, Consumer Advocate, filed a Formal Complaint ("OCA Complaint") and Public Statement in the proceeding. The OCA alleged that a 500-kwh-per-month customer's bill would increase by $9.30 per month -- from about $44.82 to $54.12, with the annual bill increasing from $537.84 to $649.44.[2]

The OCA alleges that a preliminary examination of the Company's filing indicates that the proposed charges, proposed increases and changes in rates, proposed rate schedule modifications and transfers, and proposed changes in rate policy, rules and regulations contained in the proposed Tariff are or may be unjust, unreasonable, in violation of law and will or may produce an excessive return on investment in violation of the Public Utility Code, 66 Pa. C.S.A. § 1301 *et seq.*[3]

The OCA Complaint further alleged that:

1. the Company proposes a $2.40 increase in the monthly residential customer charge, from $4.80 to $7.20 per month.[4]

2. the Company's claim for a return on common equity associated with Susquehanna Nuclear Steam Electric Station Unit 2 involves a claim for physical or economic excess capacity, disallowable under 66 Pa. C.S.A. § 1301, 1315, 1323[5],

---

[1] PP&L Rate Filing, Statement of Reasons at 1.

[2] OCA Complaint at 2 ¶ 3.C.

[3] OCA Complaint at 2 ¶ 3.F.

[4] OCA Complaint at 2 ¶ C.

[5] OCA Complaint at 2 ¶ 3.G.

insofar as the Commission has already found the facility to represent excess capacity[6];

3. unjust, unreasonable rates may result from granting claims related to nuclear and fossil fuel decommissioning costs (of more than $40 million per year)[7], costs associated with social program expenditures and costs associated with environmental remediation;[8]

4. PP&L's present rates may be excessive, unjust, unreasonable and unduly discriminatory;[9]

3 THE PARTIES' COMPLAINTS

On information and belief over 300 individuals, businesses and organizations have filed complaints against the PP&L proposed action.

The Commission has docketed complaints against the PP&L filing as R-00943271C0001, *et seq.*

The following parties have intervened or complained and have been granted active status in the case:

1. Government bodies: OCA; OSBA; OTS; USDOD and Federal Executive Agencies;

2. Businesses and business organizations: Bethlehem Steel; Central Eastern Pennsylvania Fuel Oil Dealers; PP&L Industrial Customer Alliance;

3. Nonprofits and other organizations: Commission on Economic Opportunity; University/College Coalition; Sierra Club.

---

[6] OCA Complaint, Press Release at 2.

[7] OCA Complaint, Press Release at 2.

[8] OCA Complaint at 2 ¶ 3.H.

[9] OCA Complaint at 2 ¶ 3.K.

Some 127 persons and organizations filed complaints,[10] While 11 appeared at the prehearing conference of March 7, 1995,[11] other parties may have requested active status.

4 SIERRA CLUB AND ITS INTERESTS

Sierra Club is a century-old broad-based citizens' environmental organization with active members throughout the Commonwealth. It has devoted significant resources to advocating cost-effective, environmentally benign alternatives to existing supply side utility resources.

Sierra Club is based in San Francisco, California and maintains a Pennsylvania Chapter with executive offices in Harrisburg, Pennsylvania. The organization's membership is located throughout the Commonwealth, and a state executive committee is broadly representative of the interests of the state's regions. Sierra Club members take service from virtually all of the state's energy utilities.

Sierra Club has, since its founding in 1892, been concerned with the exploration, enjoyment, and protection of wild and scenic places of the Earth. Today's agenda includes protection of the national and global environment against threats of acid rain, water and air pollution, hazardous wastes, ozone depletion and global warming. The Sierra Club works to promote the utilization of renewable resources and technologies in order to preserve non-renewable natural resources for usages for which alternatives have not been identified.

Sierra Club will be directly affected by the Commission's orders in this matter, and, in particular, the rate and service changes which PP&L proposes through its filing because, *inter alia,* over 1,600 of Sierra Club's members are customers of PP&L and pay PP&L's rates. Sierra Club's pecuniary interests will also be immediately and directly affected by the rate changes which PP&L's filing proposes since PP&L seeks to increase and redesign the rates which Sierra Club and its members pay.

5 PROCEDURAL RULINGS

---

[10] Second Prehearing Order (March 8, 1995), p. 3.

[11] Second Prehearing Order (March 8, 1995), p. 3.

Pursuant to notice, the Administrative Law Judge Michael C. Schnierle presided over a Prehearing Conference on March 7, 1995. He admitted certain intervenors and complainants to the case as parties. He adopted the following schedule:[12]

5.1 Cross of Company Witnesses: Mar 21 at 10:00 a.m., 23 and 24; Mar 27-29. All hearings are to begin at 10:00 a.m. in the Commission's North Office Building, Harrisburg PA.

5.2 Public input sessions:

Mar 30 Hburg; Mar 31 Lancaster; Williamsport Apr 3 eve; Wilkes Barre - Scranton Apr 4; Hazleton - Pottstown Apr 5; Bethlehem - Allentown Apr 6.

5.3 Filing of intervenor testimony:

5.3.1	Apr 07:	ROR and Generating Capacity
5.3.2	Apr 12:	Cost of Service, Rate Struct and Rate Design
5.3.3	Apr 14:	OTS files all its testimony
5.3.4	Apr 18:	General Accounting and All other issues

5.4 Cross of Opposing party witnesses

5.4.1	Apr 25-28:	Rate of return and generating capacity; Cost of Service, Rate Structure and Rate Design
5.4.2	May 2-3:	General Accounting

5.5 Receive Rebuttal:

5.5.1	May 5:	ROR and Generating Capacity
5.5.2	May 9:	Rate Structure, Cost of Service and Rate Design
5.5.3	May 12:	General Accounting and all other issues
5.5.4	May 12:	Co files rebuttal to OTS; OTS files rebuttal to all others

5.6 Receipt of Surrebuttal testimony/outlines:

5.6.1 May 17 (ROR)
5.6.2 May 19 (all other issues)

---

[12] Second Prehearing Order (March 8, 1995).

5.7 Cross Rebuttal and Surrebuttal witnesses, Rejoinder Testimony and Close of Record

5.7.1 May 22-26

5.8 Initial Briefs Due

5.8.1 June 15

5.9 Reply Briefs Due

5.9.1 June 26

ALJ Robert A. Christianson subsequently presided over the case. There were more than 24 hearing sessions (including public input hearings), producing more than 24 transcript volumes of more than 2,000 pages.[13, 14] More than 33 witnesses provided testimony, (this count

[13] The transcripts are not numbered by volume. They are as follows:

pp	date	purpose
1-36	March 7, 1995	PHC (Schnierle)
1-57	March 30, 1995	Pub input (Christianson)
58-87	March 30, 1995	Pub input (Christianson)
88-201	March 31, 1995	Pub input (Turner)
202-236	March 31, 1995	Pub input (Turner)
237-340	Apr. 3, 1995	Pub input (Christianson)
341-387	Apr. 4, 1995	Pub input (Christianson)
388-428	Apr. 4, 1995	Pub input (Christianson)
429-504	Apr. 5, 1995	Pub input (Christianson)
505-571	Apr. 5, 1995	Pub input (Christianson)
572-734	Apr. 6, 1995	Pub input (Christianson)
735-847	Apr. 6, 1995	Pub input (Christianson)
848-943	Mar. 29, 1995	Cross Company witnesses (RAC)
944-1066	Mar. 30, 1995	Cross of Company witnesses (RAC)
1067-1133	Apr. 25, 1995	Cross of intervenors (RAC)
1134-1399	Apr. 26, 1995	Cross of intervenors (RAC)
1400-1531	Apr. 27, 1995	Cross of intervenors (RAC)
1532-1639	Apr. 28, 1995	Cross of intervenors (RAC)

1640-1729	May 02, 1995	Cross of intervenors (RAC)
1730-1778	May 03, 1995	Cross of intervenors (RAC)
1779-1947	May 23, 1995	Cross (sur)rebuttal (RAC)
1948-2057	May 24, 1995	Cross of (sur)rebuttal (RAC)
2058-2236	May 25, 1995	Cross of (sur)rebuttal (RAC)
2237-2400	May 26, 1995	Cross of (sur)rebuttal (RAC)

Record closed on May 26, 1995

[14] The transcripts are not numbered by volume. The witnesses appeared for cross examination as follows:

pp	date	purpose
847-1066	Mar. 29, 1995	Cross of Company

Farber, Stathos

1067-1133	Apr. 25, 1995	Cross of intervenors (RAC)

Witmer (MacGregor PP&L), Yarolin (Mickens), Eisdorfer (Melia)

1134-1399	Apr. 26, 1995	Cross of intervenors (RAC)

Chamberlain (Kleppinger), Williams (Kleppinger), Schneider (Kleppinger), Hornung (Kleppinger), Felter (Kleppinger), Rooney (Kleppinger), Baron (Kleppinger), Brubaker (Brandeis), Andersen (Haynes), Johnson (Kenney OCA)

1400-1531	Apr. 27, 1995	Cross of intervenors (RAC)

Biewald (Barak SCC), Prisco (McCormick), Deardorff (Gorka), Metro (Simms)

1532-1639	Apr. 28, 1995	Cross of intervenors (RAC)

Baudino (Kleppinger ICA), Kahal (OCA Kenney)

1640-1729	May 02, 1995	Cross of intervenors (RAC)

includes as separate witnesses the additional rebuttal and/or surrebuttal testimony of some witnesses). The record closed with the last day of hearing, on May 26, 1995.

The ALJ provided at the May 26, 1995, hearing session, *inter alia,* that the service dates for the Briefs would be June 16, 1995, as "in hand" service dates, and that the ALJ would not require service on him of a computer disk. (*See* letter of May 30, 1995, from OCA's Attorney Kenney to Hon. R.A. Christianson, reciting June 16 in-hand service and June 27, 1995, reply brief due dates.) By letter ruling of Monday, June 12, 1995, the ALJ permitted Sierra Club to file its Brief on June 19, 1995, due to the unavailability of certain transcripts in the Commission's file room.

6 INTERLOCUTORY RULINGS

Brady (PP&L MacGregor), Kuennen (CEO), Sivulich (Mickens), Weakley (Simms), Kollen (Kleppinger ICA)

1730-1778	May 03, 1995	Cross of intervenors (RAC)

Catlin (OCA Kenney), Johnson (OCA McCloskey), Bridenbaugh (OCA McCloskey)

1779-1947	May 23, 1995	Cross (sur) rebuttal (RAC)

Moul (PP&L Gadsden), Deardorff (OTS Simms), Kahal (OCA Kenney), Moul (PP&L Gadsden), Hoch (DeCusatis), Krall (DeCusatis)

1948-2057	May 24, 1995	Cross (sur)rebuttal (RAC)

Farber (MacGregor), Stathos (MacGregor), Berish (Gadsden), Bernini (MacGregor), Sivulich, Catlin, Berish

2058-2236	May 25, 1995	Cross (sur)rebuttal (RAC)

LaGuardia (Gadsden), Slivka, Kleha, Kasper, Johnson

2237-2400	May 26, 1995	Cross (sur)rebuttal

Andersen, Jones, Bridenbaugh, Sipics, Hieronymus, Kahal

The ALJ made many rulings during the course of the proceedings. With respect to Sierra Club he provided that:

- Sierra Club would be admitted as a party to the case;[15]

- A portion of Sierra Club Statement No. 1, Testimony of Bruce Biewald, of Tellus Institute, regarding DSM cost recovery, would be excluded from the case;[16]

- There would be no separate record for the cross examination of the excluded testimony;[17]

- He would not certify the ruling striking the Biewald DSM testimony to the full Commission as a material question under the Commission's rules.[18]

The ALJ admitted Sierra Club exhibits 1A-1E,[19] and the balance of Mr. Biewald's testimony.[20]

ARGUMENT

1 THE ALJ SHOULD RECONSIDER HIS EXCLUSIONARY RULINGS ON DSM.

Sierra Club hereby incorporates by reference its arguments made on the record with respect to the referenced rulings excluding portions of Mr. Biewald's testimony and denying creation of a separate record for the excluded testimony.

---

[15] Second Prehearing Order (March 8, 1995), p.4.

[16] Tr Apr 27, 1995, p. 1432-33. The motion was to exclude p. 4, line 5 through p. 7 line 21, all of pp. 9-24 and related exhibits [1C]. The Industrial Customer Alliance brought the motion. p. 1408. OCA, p 1413-14, and the Company, 1412-13, supported it. OTS took no position. p. 1432.

[17] Tr. Apr. 27, 1995 p. 1436.

[18] Tr. May 26, 1995.

[19] Tr Apr 27, 1995 p. 1408.

[20] Tr Apr 27, 1995 pp. 1408, 1432-34.

We ask the ALJ to reconsider and permit the inclusion of the excluded Biewald testimony. In the alternative we request the reopening of the record to permit the cross examination of Mr. Biewald, by telephone (because his office and home are in Boston), or by deposition, to be placed in the record. The excluded testimony is already in the docket file, of course.

If the Commission reverses the exclusion, as we will request, and any party seeks cross examination, the record will have to be reopened at that time. That would lengthen these proceedings unnecessarily. However, there is an easy solution to the time question. In reply to this Sierra claim, the interested parties could state to the ALJ whether they would waive such a reopening of the record, agreeing to the testimony coming into evidence without cross examination, should the ALJ or the Commission reverse.

We ask the Commission to note that we have taken every step appropriate to accommodate the schedule in this case. If the testimony is admitted, the parties seeking to cross examine should be required to offer a method that (1) saves Sierra Club harmless from the expense of flying Mr. Biewald back into Harrisburg and paying for his time, approximately $1,000 for time and expenses, and (2) offers the least disruption to the already extremely tight schedule.

2 DSM COST RECOVERY: THE COMMISSION SHOULD ADDRESS INCENTIVES AND LOST REVENUES NOW.

The Commission should address DSM cost recovery in this case, because the opportunity for addressing PP&L incentives and lost revenues may not come until another rate case in the next century. With respect to demand side management ("DSM") expenditures and expenditure levels the Commission should:

- allow direct cost recovery for reasonable and prudent programs;
- allow incentives for reasonable administration of prudent programs, calculated according to the spread embedded in the pricing of PP&L's off-system sales;
- allow the recovery of lost revenues associated with the DSM programs, according to just and reasonable measures;
- require the implementation of programs to secure all cost-effective DSM, as measured by the TRC test;

- require the Company to use all cost-effective DSM means to reduce uncollectible accounts expenses[21].

Mr. Biewald attempted to testify as to the appropriate method for addressing these matters while the DSM Order of the Commonwealth Court is subject to a petition to review in the Pennsylvania Supreme Court. On motion of the industrial customers, and with OCA and Company support, the ALJ excluded the testimony. If the testimony had been allowed and adopted, the Commission would have provided PP&L's customers with a choice in energy services -- the opportunity to secure cost effective DSM.

The law is that the Commission can only set up a DSM incentive mechanism in a full rate case. Until and unless the Supreme Court grants allocatur, the Commonwealth Court decision on the Commission's December, 1993, DSM Cost Recovery Order is the law. The Opinion provides that the Commission can find and set up DSM incentives only within the context of a full-blown cost of service review in a rate case. Given PP&L's prediction that the Commission will not see it for another general base rate case until after the turn of the millennium, the instant case is the best opportunity for the Commission to do what it ordered in its 1993 DSM cost recovery order -- decide upon a level of DSM incentive payments that will attach to a reasonably and prudently run and Commission-approved DSM program.

This is the Commission's best opportunity to address apparently implied weaknesses in its lost revenue recovery justification. The Commonwealth Court decision also provides the Commission with the opportunity to address the facts and the law supporting DSM lost revenue recovery in a remand proceeding or in a general rate case. It appears that the Court may have been implying that the Commission 1993 Order had failed to provide the Court with a complete justification of the lost revenue scheme.

The instant case presents an excellent opportunity to address the lost revenues issue -- to "road test" it. The case is already opened and noticed, with all the parties who would address the matter for PP&L's rates in a generic case, anyway. The Company, OTS, OCA, OSBA, low income advocates, industrial customers and environmental representatives were parties to the DSM cost recovery generic proceedings.

There is a strong tactical reason for the Commission's addressing lost revenue recovery in the instant case.. As a matter of tactics, the industrial customer group, which was the principal antagonist to the DSM Cost Recovery Order, stands only to gain by maneuvering

---

[21] *See, e.g.*, PP&L Rate Filing, Statement of Reasons at Book Statement B-4, p. 5 of 6, Statement of Operation and Maintenance Expenses, acct line 904, Customer Accounts Expenses, Uncollectible accounts $16,932,000.

the lost revenues legal debate into a generic case and away from this case. They can take one "shot" at the Commission's legal analysis of lost revenue recovery in an inevitable appeal of the generic decision. By contrast, if the Commission permits the legal and factual debate on lost revenue recovery to go forward in the instant docket, it has an opportunity to examine the industrials' attack in this limited, one-company, context. Then, if a generic or other case(s) is to be held, the Commission can correct any weaknesses the industrials would have attacked in an appeal of a PP&L order.

Thus, the Commission should reverse the ALJ's exclusionary ruling, permit cross, any rebuttal and any surrebuttal in a manner that will not prejudice Sierra Club, and take briefs on the DSM cost recovery issues. Then, as we will argue on supplemental brief, the Commission will have the power and the evidentiary basis to establish a complete DSM cost recovery mechanism for PP&L.

3 COST OF SERVICE ISSUES

3.1 The Company's ECR should terminate in order to foster the most economically efficient purchases of energy resources.

The ECR is a benefit to the Company, not a right. It, in fact, functions as a subsidy to the use of the covered energy sources because it lessens the Company's risk in relying upon them.

ECR treatment of power purchases and fuel expenses should be denied unless the Company can demonstrate that it has maximized the benefits of wholesale market purchasing for its customers, and, in particular, that its purchases are the product of least cost competitive bidding or its substantial equivalent conducted at arms' length from intra-Company sources and affiliates and extra-Company sources.

The proposed treatment of the JCP&L contract termination through the ECR should be denied until and unless the Commission can find that the Company has complied with new competitive bidding regulations in dedicating the capacity and energy for its customers.

4 RATE DESIGN

4.1 The customer charge should be set at $4.80 because a high customer charge sends the wrong economic signals.

The Company maintains its claim for a $7.20 residential customer charge through the rebuttal phase of the case.[22] The Commission should view the claim as a throwaway, largely a bargaining chip to be lost in favor of other claims.

The OCA and CEPFOD positions are fairer, and are grounded in the economics of an industry moving toward the competitive sale of energy services.

The meter, or hookup to the grid, is the least competitive, most monopolistic aspect of all customers' services. Because residential customers, as small customers, have less market power than those of other classes, the Commission has a special obligation to protect them.

A large customer charge sends the wrong price signals to customers. As long as the supply of fuels is limited, and utility distributors would have to secure additional power sources with growing load, there is a benefit to tagging the consumption of kWh's with its true costs. Reasonable and prudently incurred costs for a mature system like PP&L's should attach to the energy component of the customer's bill. The Commission should not increase the customer charge.

Assuming *arguendo* that the Commission alters the customer charge, there is a strong case to spread the costs within each class proportionately to consumption blocks -- the more a customer uses, the more likely (s)he is to pay an increment to the customer charge. (By contrast, simplicity would, of course, require that the charge attach to the customer, not to the consumption block, as PP&L suggests[23].) The Commission could find that additional costs are trackable to higher consumption residential customers, those in new subdivisions of bigger, air-conditioned or electrically heated houses farther away from population centers. Thus, with consumption divided into blocks, the more a customer used, the greater the customer charge to be paid.

Assuming *arguendo,* again, that the Commission alters the customer charge, there are solid reasons to mate customer charges with consumption. Higher consumption brings with it predictably higher costs, as the distributor must contract for additional firm load. An inclining block structure, be it one for the customer charge or one for kWh consumption, positions the utility's captive customers for the likely restructuring of the Pennsylvania electric utility industry, and PP&L. PP&L customers may well be served by other than a non-vertically-integrated electric distribution company before the next rate case. Inclining block rates will help put off the day when the distributor must secure new, higher cost

[22] PP&L Statement 8-R (Kasper rebuttal).

[23] PP&L Statement 8-R (Kasper rebuttal) p. 8.

resources. Indeed, just as "[l]oad management measures need a long-lead time compared to supply side options" (PP&L's Mr. Kasper)[24], the inclining block customer charge requires the next few years to produce its benefits.

The Company proposal for a declining block customer charge is self-contradictory. The Company's proposal to replace the RTS thermal storage rate with a new tariff incorporating available central load control devices[25] rests on a recognition that avoiding the acquisition of new peaking resources will cut costs. Similarly, the rate structure for the customer charge, if not the commodity charge, should recognize the extra burden that poor load factor customers place on the system at peak times.[26]

4.2 Biewald Testimony: The Commission should require maximum cost-effective DSM as a prerequisite to economic discount rates.

We urge the Commission to act, rather than REact, to changes in the electric utility industry. Tellus' Bruce Biewald provided a well-reasoned proposal to protect the integrity of the region's ability to supply reliable, economical and environmentally benign power -- no DSM, no discounts.

The Commission should require as a precondition to eligibility for any promotional or discount rate, including "economic development rates", that a business customer be initially and periodically certified through an approved independent auditor that it has undertaken to cost-effectively maximize the energy efficiency of its operations, as measured for the period that the rate is expected to be in effect for it, OR that it has in place an approved plan for such cost-effective measures. PP&L, and ultimately each other electric utility in the state, must demonstrate that any industrial customer seeking an economic development rate discount use the maximum amount of the cheapest, most environmentally responsible, source of energy services for Pennsylvanians -- cost-effective demand side management -- to lower its bills.

---

[24] PP&L Statement 8-R (Kasper rebuttal) p. 14.

[25] PP&L Statement 8-R (Kasper rebuttal) p. 12.

[26] This operating burden is different from that associated with the Company's past investment in high-capital-cost baseload facilities, in order to meet the requirements of high load factor customers for relatively large amounts of reliable, round-the-clock power. *See* OCA Statement No. 3, Direct Testimony of Dr. Charles Johnson, pp. 9-13.

Sierra Club's witness, Bruce Biewald, of the Tellus Institute in Boston, is an MIT grad with 15 years' experience in utility systems planning.[27] Mr. Biewald has testified in dozens of regulatory proceedings on energy issues and has consulted for business, government, consumer advocate and environmental clients.[28]

Mr. Biewald made the following conclusions and observations:

Economic Discount Rates - Conclusions

1. Economic discount rates have the potential for creating inequities among customer classes.

2. It is possible to reduce the amount of the rate discount, and therefore any associated inequities, by structuring the tariffs to require participating customers to adopt cost effective DSM measures. An efficiency requirement can be included in the terms and conditions for the discounted rate.

3. To the extent that utility shareholders absorb some of the revenues that are lost as a result of economic discount rates, the utility will have an incentive to minimize the amount of the discount rate, through negotiations with the customer and with cost-effective DSM programs.

4. It is possible to reduce the inequities created by discount rates by providing all customers with access to cost-effective DSM programs.

Economic Discount Rates - Recommendations

1. The Commission should require that large industrial or commercial customers demonstrate through certified energy audits and proof of work done that they have already implemented, or have made a commitment to implement, maximum cost-effective DSM measures before they may participate in PP&L's discount rate programs.

[27] Sierra Club Statement 1 (Biewald) pp. 2-3, Sierra Club Ex. 1A-1B.

[28] Sierra Club Statement 1 (Biewald) pp. 2-3, Sierra Club Ex. 1A-1B.

2. PP&L should be required to minimize the inequities caused by economic discount rates by providing a meaningful option for cost-effective DSM programs to all customers.[29]

There is precedent for the DSM-discount rate proposal. New York requires "independent and comprehensive DSM audits" of industrial customer premises and processes as a condition for eligibility for flexible rates.[30] New Jersey's recently-adopted Energy Master Plan suggests that the New Jersey Board of Public Utilities include in draft flex rate legislation a requirement that prospective flex rate customers undergo a comprehensive energy audit.[31] Indeed, a NJ Senate bill proposes that, upon application of a utility for a retail discount rate:

> 3.c(4) Evidence of a comprehensive energy audit of the customer facility must be submitted to the utility prior to the effective date of the discount rate agreement.[32]

The economics for the Biewald proposal are win-win-win; by contrast, the economics for the Company's economic development rate proposal, or the rate it would replace, are largely a loser for all.

The typical economic development rate is a relatively negative, reactive measure. The term is, indeed, a misnomer because nothing is being developed. The rate is a tool to maintain a difficult status quo by simply reducing the industrial customer's bill for a set amount of electricity. Either the utility's shareholders or the other customers absorb the difference in revenues, and the customer's production processes are no more efficient than before. The economic development rate is an economic preservation rate.

The Biewald proposal is a positive one. It enhances economic growth and provides an opportunity for all parties to gain. The net of the industrial customer's DSM+ED rate investment should equal or surpass the standard-operating-procedure rate reduction. The

---

[29] Sierra Club Statement 1 (Biewald) pp. 7, 25-30.

[30] Opinion and Order Regarding Flexible Rates, No. 94-15, Case 93-M-0229 (July 11, 1994), p. 31 ¶ 5 (excerpt attached as Sierra Club Att. C).

[31] New Jersey Energy Master Plan (March 1995), p. 26 (excerpt attached as Sierra Club Att. E).

[32] N.J. Senate Bill S-1940 § 3.c(4), p. 3 (Proposed 1995) (excerpt attached as Sierra Club Att. F).

utility winds up offering a more modest rate break, and increased efficiencies at the customer's premises may actually increase production, and kWh sales. The other customers benefit from the increased local economic activity as the industrial customer invests in DSM measures and increases production, if not power purchases, due to increased efficiency.

Indeed, the Commission should require the Company to enhance the choices available to its customers by providing and marketing to ALL classes of customers discounted tariffs, predicated upon the appropriate certification that the customer has engaged, or is engaged actively, in comprehensive DSM activities and investments to cost-effectively minimize the consumption of electricity, including the customer's contribution to class coincident peaks.

4.3 Biewald Testimony: The Commission should require a system benefits charge as a component of each kWh, to cover the cost of such benefits to all customers as low income programs, pollution control, and DSM.

We ask the PUC to create a "system benefits charge" on each kWh distributed by the utility, folding in those programs and resources that uniquely benefit local customers. Mr. Biewald has recommended the charge cover DSM, low income programs and other environmental costs. Regardless of how industry restructuring affects Pennsylvania the Commission should position PP&L and its customers now to protect these valuable programs from retail wheeling bypass.

It now appears that the restructuring debate will extend over a period of years. The Commission could use a near-term strategy that can sustain progress on crucial long-term investments while that debate proceeds. The Biewald recommendation for a system benefits charge addresses the very concern that NARUC recently expressed regarding "potentially stranded benefits".[33]

The National Association of Regulatory Utility Commissioners, NARUC, passed a resolution supporting the protection of "stranded benefits" at its November 1994 annual meeting in Reno, Nevada.[34] NARUC concluded that "it is the responsibility of state and federal electric utility regulators to assure that those vital public benefits are not 'stranded', but are well served in new electric industry structures and in the transition to them." These benefits include, according to NARUC:

---

[33] Sierra Club Statement 1 (Biewald) p. 31.

[34] Sierra Club Exhibit 1E, "Resolution on Competition, the Public Interest, and Potentially Stranded Benefits".

- "systematic investments in energy efficiency";
- "responsible management of the environmental impacts of electric generation;
- "innovative rate designs ... [in] meeting the specific needs of low-income customers";
- "system reliability and fuel diversity";
- "research and development for the electric industry".[35]

Indeed, to the extent that such peak reduction measures as DSM can save PP&L and PJM from, for example, the unforeseen loss of 2,000 MW of the Salem nuclear plant's baseload contribution during the summer peak, they are worth protecting and encouraging. ("Two Salem nuclear plants are shut down; an NRC spokesman said the latest problems have only added to the disappointment with the units". (Philadelphia Inquirer, June 10, 1995, p. B1.)

The solution to the stranded investment challenge lies in converting cost recovery for energy efficiency, low-income services and R&D to a non-bypassable, usage-based "system benefits charge" on electric distribution services. Cost-effective renewable energy acquisitions should also qualify to the extent that their initial cost streams exceed short-term commodity costs. This would create a cost recovery structure that can accommodate strong performance-based incentives and retain consistency with all plausible restructuring outcomes.

There is precedent for such a charge in Pennsylvania. Washington's Utilities and Transportation Commission recognized the value of a system benefits charge in its December 14, 1994, meeting, in approving Washington Water Power's proposal for a usage-based distribution charge to recover energy-efficiency investments.[36] Idaho followed in March of 1995.[37]

The recommended cost-recovery system requires no change in current rates or rate structures. PP&L and other utilities today typically recover "stranded benefits" charges from all distribution system users based on volume of consumption; they would continue to do so

---

[35] Sierra Club Exhibit 1E.

[36] APPLICATION OF WASHINGTON WATER POWER, Docket No. UE-941375, UE-941377 (Minute Order of Dec. 14, 1994, Wash. Utilities. and Transportation Com'n), WWP Petition for Tariff Revisions, Schedule 91, "Experimental DSM Rider Adjustment - Washington" (Sierra Club Att. A); WPP Petition WUTC Staff Recommendation for Approval (Sierra Club Att. B); Sierra Club Statement No. 1 (Biewald) p. 33.

[37] Application of Washington Water Power, Case No.'s WWP-E-94-10, WWP-G-94-5, Order No. 25917 (Idaho PUC Mar. 6, 1995) (Sierra Club Att. D).

under the new system. The only difference is that the Commission would make explicit (as Idaho and Washington now have) that distribution system users cannot bypass their share of contributions to stranded benefits by designating a new supplier of kiloWatt-hours over the integrated grid (assuming that Pennsylvania ever decided to permit this).

Mr. Biewald came to the following conclusions and made these recommendations:

Recovery of DSM Costs Through a System Benefits Charges - Conclusions

1. As the debate over electric utility industry restructuring has evolved, utilities have become increasingly concerned that price increases due to DSM cost recovery will place them at a competitive disadvantage and encourage large customers to leave the system.

2. Cost-effective DSM programs provide a variety of resource benefits that accrue to *all customers* on the utility system.

3. A "system benefits" charge can be designed to ensure that all customers pay for their share of the DSM program costs, and to prevent uneconomic bypass of a utility system. The charge would be "volumetric", assigned on the basis of consumption, rather than a customer, basis.

4. A system benefits charge would enable PP&L to recover all appropriate DSM costs under a variety of future restructuring and competition scenarios, and would not place PP&L at a competitive disadvantage with regard to retail wheeling or self-generation. Appropriately designed, a system benefits charge may also provide the vehicle for this Commission to position Pennsylvania utilities for industry restructuring.

Recovery of DSM Costs Through System Benefits Charges - Recommendations

1. The Commission should establish a non-bypassable system benefits charge for recovering DSM costs.

2. The Commission should establish a DSM cost recovery mechanism which (a) allows PP&L to recover all appropriate DSM program costs, (b) prevents uneconomic bypass, and (c) will be appropriate under a variety of future electricity industry restructuring scenarios.

3. The Commission should make all approved DSM programs, including low income and other DSM programs, subject to the non-bypassable system benefits charge. The

> Commission should also consider including other utility expenditures in the charge, perhaps those for environmental benefits.[38]

There should be no federal preemption of a system benefits charge. The Federal Energy Regulatory Commission (FERC) acknowledges state ratemaking authority over distribution services. While the boundary between state-regulated distribution and FERC-regulated transmission may prove to be blurred, there should be no dispute as the boundary's existence.

In the March 29, 1995 Notice of Proposed Rulemaking, the "MEGA NOPR", FERC explicitly endorsed state and local regulators' right to use distribution charges to avoid "stranded benefits" from utility investments in energy efficiency. The agency confirmed that nonfederal regulators "may also use their jurisdiction over local distribution facilities to address potential 'stranded benefits', e.g., environmental benefits associated with conservation, load management, and other demand side management (DSM) programs."[39] FERC cited NARUC's resolution on "stranded benefits".[40]

We request that the Commission order PP&L to segregate in a system benefits charge its low income, DSM, R&D and other environmental costs, allocating those costs on the same per-kWh formula as it would have without the identified charge.

RELIEF REQUESTED

Sierra Club requests, as relief, that the Commission:

d. Reverse the ALJ and receive into evidence the Biewald DSM cost recovery testimony;

e. After providing the public with adequate notice, and AFTER THE COMPLETION OF THE FORMAL PARTIES' EVIDENTIARY HEARINGS herein, so that the issues before the public may be properly developed and focused, hold public input hearings throughout PP&L's service territory in

---

[38] Sierra Club Statement 1 (Biewald) pp. 7-8, 31-33.

[39] 60 Fed. Reg. 17662, 17691 n. 230, 17711 n. 304 (Apr. 7, 1995).

[40] 60 Fed. Reg. 17662, 17691 n. 230, 17711 n. 304 (Apr. 7, 1995).

order to provide its customers with an opportunity to be heard on the record, and make the testimony and exhibits received therein a part of the record;

f. Deny any increase or change in PP&L's rates that is unjust, unreasonable, unduly discriminatory or inconsistent with the Public Utility Code, sound ratemaking principles, and public policy;

g. Determine the justness and reasonableness of Respondent's current and proposed rates;

h. Adopt the recommendations and proposals advocated in this Brief;

i. Grant all other relief to which Sierra Club is entitled; and

j. Grant such other relief which the Commission may deem to be necessary and proper.

Respectfully submitted,

Alan J. Barak,
Attorney for Sierra Club

Alan J. Barak (Sup. Ct. No. 67886)

Mid-Atlantic Energy Project
Widener University Energy Law Clinic
3700 Vartan Way
Harrisburg PA 17110

717/541-1967 voice
717/541-1970 fax

Daniel W. Rosenblum, Director MAEP, Of Counsel[41]
Dated: June 16, 1995

\ppl1\brief1.pld

---

[41] Member Illinois and New York bars.

COMMONWEALTH OF PENNSYLVANIA
BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-000943271
	)	
Pennsylvania Power & Light Co.	)	
(General rate increase request)	)	

SIERRA CLUB'S BRIEF

ATTACHMENTS

TABLE OF ATTACHMENTS

Att A: APPLICATION OF WASHINGTON WATER POWER, Docket No. UE-941375, UE-941377 (Minute Order of Dec. 14, 1994, Wash. Utilities. and Transportation Com'n), WWP Petition for Tariff Revisions, Schedule 91, "Experimental DSM Rider Adjustment - Washington"

Thomas D. Dukich
Manager, Rates and Tariff Administration
The Washington Water Power Company
E. 1411 Mission Avenue
P.O. Box 3727
Spokane, Washington 99220
Phone: (509) 482-4724 Fax: (509) 482-4879

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

IN THE MATTER OF THE APPLICATION OF	)	
THE WASHINGTON WATER POWER	)	DOCKET NO. UE-
COMPANY FOR APPROVAL OF REVISED	)	
GAS AND ELECTRIC TARIFFS FOR	)	DOCKET NO. UG-
IMPLEMENTATION OF ENERGY EFFICIENCY	)	
PROGRAMS FOR RESIDENTIAL,	)	
COMMERCIAL, AND INDUSTRIAL	)	
CUSTOMERS	)	

THE WASHINGTON WATER POWER COMPANY

SCHEDULE 91

EXPERIMENTAL DSM RIDER ADJUSTMENT - WASHINGTON

APPLICABLE:

To Customers in the State of Washington where the Company has electric service available. This DSM Rider or Rate Adjustment shall be applicable to all retail customers for charges for electric energy sold and to the flat rate charges for Company-owned or Customer-owned Street Lighting and Area Lighting Service. This Rate Adjustment is designed to recover costs incurred by the Company associated with providing Demand Side Management services and programs to customers.

MONTHLY RATE:

The energy charges of the individual rate schedules are to be increased by the following amounts:

Schedule 1	- .073¢ per kWh	Schedule 25	- .047¢ per kWh
Schedule 11 & 12	- .103¢ per kWh	Schedule 31 & 32	- .061¢ per kWh
Schedule 21 & 22	- .075¢ per kWh		

Flat rate charges for Company-owned or Customer-owned Street Lighting and Area Lighting Service are to be increased by 1.55%.

SPECIAL TERMS AND CONDITIONS:

Service under this schedule is subject to the Rules and Regulations contained in this tariff.

The above Rate is subject to increases as set forth in Tax Adjustment Schedule 58.

Issued October 26, 1994 Effective January 1, 1995

Issued by The Washington Water Power Company

By Thomas D Dukich, Manager, Rates & Tariff Administration

WWP DSM PROGRAMS AND TARIFF RIDER

WUTC BUSINESS MEETING--TALKING BULLETS
DECEMBER 14, 1994

---

1. History and Context

a. WWP initiated this particular phase of our DSM program in 1992

b. Mid-course corrections were approved in September of 1993 and April of 1994

c. Currently effective tariffs will expire on December 31, 1994

d. This DSM program has saved 34 aMW at a cost of 2.7¢ per kwh

e. Electric savings were higher than estimated and came in under budget

f. WWP has stopped deferring DSM capital costs and has begun to amortize the current electric DSM balance--$37,000,000 ($57,000,000 system) with no rate increase to customers

g. Since 1990 we have met over 2/3 of our load growth with DSM

h. WWP's electric rates have increased by only 2% since 1987

2. Events Leading to WWP's Current Proposal

a. WWP has pursued and acquired resources covered in our 1993 Least Cost Plan

b. DSM, Hydro up-grades, peaking resource (Rathdrum simple cycle turbine) and an updated load forecast--result is a new projected resource need

c. We don't anticipate an energy deficit until the year 2010 and don't see capacity deficits until 2006

d. Our proposed DSM programs are exactly in line with our 1993 least cost plan--a total of 11 aMW for combined 1995 and 1996

3. Why Continue DSM With No Near-Term Resource Need?

a. Maintain continuity of energy efficiency programs--minimum viable program at a level we would keep in place for the foreseeable future

b. Keeps fixed overheads from driving up unit cost per kwh

c. Avoid stop/start-stop/start problems

d. Refocus programs on market transformation through codes, education, experimental programs--consistent with Power Council's recent position

e. Provide customer service and value--our recent survey shows 95% of customers support doing some DSM even in the absence of resource need; 83% said they would pay $1.00 per month to support DSM

f. Maintain resource diversity and flexibility by keeping DSM in the resource mix--stay in the ready mode

g. However, prudent cost management dictates that we should do no more than is needed to meet the above criteria

4. Circumstances Which May Demand a New Approach To DSM

a. We are acquiring DSM during a period when WWP does not have a clear need to acquire resources--from a public policy perspective this may require a new look at how DSM is handled

b. There is considerable discussion about how competition and possible retail wheeling may threaten or cause a decline in DSM

c. Financial institutions are becoming increasingly concerned about the magnitude and life of regulatory assets--recent WWP analyst meetings concentrated on regulatory assets and capital budgets

d. A considerable number of jurisdictions have either implemented or are discussing alternative forms of regulation for all types of utilities

5. WWP's Proposed Tariff Rider is a Good Solution to the Above

a. The rider collects revenue by having a relatively small charge on the kwhs or therms delivered over WWP's distribution system--a "wire charge"

b. Our customers buying wheeled or transported energy will still pay for DSM under the public policy assumption that it is desirable to save energy no matter where it comes from, WWP's system or other producers

c. DSM costs are expensed in the year they occur

d. This reduces unit DSM costs by 15% compared to traditional rate base treatment--no return to shareholders and no lost margin recovery

e. WWP feels this is reasonable accounting treatment given the levels of DSM being proposed and given the lack of near term resource need

f. WWP does not build up a regulatory asset under this mechanism of offsetting revenues and expenses

g. WWP will also accelerate the amortization of the existing $37,000,000 of electric DSM rate base and the $5,500,000 of gas DSM rate base by 5 years (from 19 years to 14 years) if the tariff rider is approved

h. Commission staff audit work indicates that the company is not in an over earning position when compared to today's financial indicators

i. Our recent survey results indicate that customers would prefer to pay for DSM now in order to lower future costs--69% would rather pay $1.00 now than $1.50 six years from now

j. The survey also indicates that 83% of customers are willing to pay $1.00 per month for DSM

k. A mechanism that provides for current DSM cost recovery is specifically allowed by Washington state law

l. A single relatively small rate change (1.55% for electric and 0.52% for gas) will collect enough in revenue to provide for a consistent base level of DSM--also avoids internal budget pressures

m. The rider is earnings neutral to WWP with the exception of lost margins--lost margin recovery is not being proposed in this filing

n. The rider eliminates some disincentive and risk to the Company

6. Why We Have Asked the Commission to Decide Today?

a. Current tariffs expire on December 31, 1994 and in the Company's judgement extending those tariffs would lead to levels of DSM that are not justified by resource need

b. There is much conceptual agreement among parties but our collaborative has not resulted in unanimous agreement--but we have come to better understand each others points of view

c. Issues of DSM magnitude seem to be the main source of disagreement

d. Ultimately, WWP bears the burden of demonstrating prudency so as it has done in past situations, the Commission may decide that it is reasonable to let the Company use its best judgement and bear the consequences of the decision it makes--avoid over or micro-managing the Company

e. The tariff rider would be revisited after two years

f. The Company is at risk for defending the prudency of DSM expenditures even though they are expensed in the current year

g. WWP has agreed not to invoke a retroactive rate making argument should prudency become an issue

7. Summary

a. We are asking the Commission to approve our DSM programs and program levels

b. We are asking the Commission to approve this innovative DSM rider approach--to our knowledge this is not being done this way anywhere else in the U.S.

c. This is a two year experiment--this limits risk and we can evaluate continuing at that time if result are as positive as we expect

d. There is a relatively small impact on customers--81¢ per month for residential electric customers and 18¢ per month for residential gas customers

e. This approach limits the build up of regulatory assets

f. This approach will keep DSM at a consistent funding level and will keep interest expense and carrying costs to a minimum

Contents of the Company's Petition

Contents of the Company's Petition (CONTINUED)

I. EXECUTIVE SUMMARY

The Washington Water Power Company ("Applicant", "WWP" or "company" herein) respectfully petitions the Commission for approval of tariff revisions related to its demand-side management (DSM) programs.

Background

The majority of the company's current DSM programs were approved in 1992 with mid-course adjustments approved in 1993 and 1994. The filing approved in 1992, which was responsive to the Commission's 1991 Notice of Inquiry ("NOI") on barriers to least cost planning, included accounting treatment on an experimental basis which, in general, allows the company to defer its investment in DSM for later recovery, to defer certain lost margins, and to accrue allowance for funds used conserving energy ("AFUCE").

The 1992 DSM filing included a fuel efficiency program in which electric space and water heat equipment was replaced by natural gas space and water heating equipment. To the company's knowledge no program of this nature had been offered in the Northwest and few, if any, of this magnitude in the U.S..

Many of the programs included in the 1992 DSM filing are scheduled to "sunset" at the end of 1994. These programs were to be re-evaluated in light of program experience and circumstances facing the company going into 1995.

Current Filing

This filing is unique in that WWP is requesting Commission approval for the company to continue to acquire additional electric energy and capacity resources at a time when it does not have a near- or medium-term need for these resources. In this case, company forecasts indicate that WWP does not need the resources proposed in this filing for approximately ten years. Thus, continued acquisition of DSM must be justified for reasons other than resource need alone.

The company believes that it is reasonable to continue to acquire some level of DSM. The DSM Issues Group (DIG), established in 1992 to review issues related to the company's three year experimental program, discussed future levels of DSM acquisition. All DIG members agreed that the company should continue to acquire some DSM. The group, however, did not reach consensus on the level that is necessary in order to achieve the desired objectives. The company's primary objectives in its proposal to continue acquisition of DSM include:

1. *Maintaining continuity in the promotion and support of energy efficiency;*
2. *Providing for long-term resource diversity;*
3. *Recognizing the timing of resource needs;*
4. *Promoting the transformation of consumer markets to energy efficient choices; and*
5. *Providing customer service value.*

The company's proposal is supported by the following considerations:

1. *Existing company resources are adequate to meet customer energy and peak requirements until 2010 and 2006, respectively;*

2. *The company's last Integrated Resource Plan (IRP) called for DSM of approximately 4 aMw per year over the next 10 years, compared with the proposed acquisition of 5.7 aMW in 1995 and 5.3 aMW in 1996;*

3. *DSM supply curves show "market potential" over the next 10 years to average between 2.5 aMW/year at 4¢/kwh levelized (real); forecasted load growth is estimated at 8 aMw per year;*

4. *The majority of lost opportunities are captured through available programs and codes;*

5. *Analyses show that acquiring DSM beyond the needs of the company's retail customers for wholesale to other utilities would lead to higher prices for the company's retail customers; and*

6. *A report issued by the U.S. Department of Energy's Oak Ridge National Laboratory indicates that U.S. electric utilities' DSM expenditures in 1992 averaged 1.3% of revenues. By comparison, the company's proposed 1995 electric DSM expenditures is 1.2% of revenues.*

In this filing, the company is proposing to spend $9.4 million, over the next two years, to acquire an estimated 10 aMW of energy and 22.9 MW of capacity through DSM. WWP proposes the acquisition of 5.7 aMW of electric energy and approximately 11.9 MW of capacity in 1995 at a cost of $5.7 million, with programs available to residential, commercial and industrial customers. In 1996, an estimated 5.3 aMW of electric energy and 11 MW of capacity would be acquired at a cost of $3.7 million. Expenditures for 1995 are higher than 1996 due to carryovers resulting from current tariff commitments. The company is also proposing natural gas DSM acquisition of 198,500 therms in 1995 and 174,000 therms in 1996 at a cost of $475,000 and $378,000, respectively.

The average levelized cost of the electric savings are 1.59¢/kwh and 0.97¢/kwh in 1995 and 1996, respectively. Natural gas savings average a levelized cost of 0.34¢/therm in 1995 and 0.32¢/therm in 1996.

DSM Tariff Rider Proposal

The company also requests approval of a two year experimental DSM tariff rider. The rider would be a separate charge to provide funding for the DSM programs offered to customers. The company is proposing this DSM tariff rider as a pilot to replace the current accounting treatment. The tariff rider would resolve several major concerns facing the company regarding DSM acquisition. The proposal strikes a balance among the many issues that surround DSM acquisition in the face of the changing utility environment including retail wheeling.

While the Rider is clearly WWP's preferred approach, in the alternative, the company proposes that the accounting treatment most recently approved by the Commission continue for "new" DSM costs incurred in the future. DSM costs would be deferred and capitalized. WWP notes that it has started amortization of the approximately $68 million investment balance associated with the two year

DSM experimental programs. Application of the most recently approved accounting treatment would allow the company to defer amortization of "new" DSM to the end of the rate freeze period.

DSM Issues Group

In the past two years, the DSM Issues Group ("DIG") participated in 24 meetings. We reached varying degrees of consensus although we did not reach agreement on future levels of DSM acquisition. However, the company has incorporated several points of view from the DIG in determining the proposed level and program design.

Other

Although not directly related to this Petition, it is important to note, as mentioned earlier, that Water Power and Sierra Pacific Resources have requested authorization to merge companies. The companies have requested regulatory approvals by September 1, 1995.

This DSM tariff application is related solely to WWP. Because WWP and Sierra will become separate operating divisions, the company does not anticipate near-term changes to its DSM programs for WWP customers as a result of the merger. Acquisition of DSM for the merged company will be determined as part of its integrated resource process.

For informational purposes, Sierra Pacific's DSM acquisition plan for 1995 and 1996, as included in its 1993 IRP, is for 3 aMW in each of 1995 and 1996 at a cost of $6.3 million and $6.7 million, respectively. These expenditures represent approximately 1.5% of Sierra Pacific's revenues.

The company requests that the Commission approve the proposed DSM tariff changes included in this filing to become effective January 1, 1995.

benefits. Attachment N describes the TRC cost-effectiveness methodology used by the company.

Attachment C provides an explanation of the manner in which the company would implement the revisions for each program, the cut-off dates, and the manner in which the changes could be communicated to customers.

VI. DSM TARIFF RIDER

A. Introduction: As discussed above, several factors impact WWP's decisions related to the acquisition of DSM. In addition to those noted above, other factors include capital budget issues, creation of regulatory assets through deferral of DSM amortization, competitive pressures, and recognition of lost margins.

The company proposes a mechanism, called a "DSM Tariff Rider" (or "Rider"), which would substantially reduce the company's concerns. The Rider would provide funding for the specific DSM programs offered by the company through a separate tariff rate assessed on energy transmitted over WWP's distribution system.

WWP views this proposal as a measured response to industry changes which:

- addresses retail wheeling concerns related to DSM,
- is consistent with policy and rate recovery issues of the WUTC, and
- does not require a general rate case to implement.

B. Underlying Policy and Legal Support: The Idaho Commission has discussed in several informal workshops the NARUC goal of "making the company's least cost plan its most profitable plan". In the Resource Management Plan process, the Commission has concurred with treating DSM as a resource. Procedurally, if acceptable to the Commission, the Tariff Rider could be added to the existing Power Cost Adjustment on a tracking basis.

In the company's view, the proposed rider should not set precedent for indiscriminate use of selected cost recovery mechanisms for selected expenses given the specific underlying policy support for DSM. (End of Idaho section.)

C. Benefits: The DSM Tariff Rider would provide the following benefits:

1. Funding for the DSM programs would be provided through a tariff linked to the DSM measures; the funding would be used solely to cover costs directly associated with the DSM programs.

2. Current funding of DSM through the DSM tariff rider would essentially eliminate capital budget concerns with regard to DSM and would provide a stable, predictable source of DSM funding.

3. Current funding would allow DSM costs to be expensed rather than capitalized which would lower the total cost of DSM to customers by eliminating the income tax effects and AFUCE associated with traditional rate base treatment.

4. Current funding through the DSM tariff rider would avoid building "regulatory assets" on the utilities books related to DSM, which is becoming an increasing concern of financial rating agencies.

5. Retail wheeling would not threaten DSM, under this proposal, since the DSM funding would be based on any energy, regardless of the supplier, delivered over the company's distribution system.

D. Rider Proposal: The DSM Tariff Rider, expressed in cents/kwh and cents/therm, would be applied to all retail energy sales transmitted over the company's distribution system for all customer classes except for special contract customers. The Rider rate would be included as separate Schedules 91 and 191--Experimental DSM Rider. The rate would be set such that funding would match anticipated DSM program costs. To the extent that funding does not match program costs, the difference, whether positive or negative, would be deferred to a balance sheet account. As the DSM programs on Schedule 90 and 190 are modified over time, the DSM tariff rider rate would also be adjusted, up or down, to match actual funding with DSM program costs and to keep the deferred balance as close to zero as possible. A carrying cost would be accrued on any balance in the account.

All DSM expenditures funded through the rider, would be subject to a prudence review at the time of the company's next general rate case.

The DSM tariff rate is proposed to be:

Electric	Rider Rate	% Increase
Schedule 1	0.070 ¢/kwh	1.55%
Schedule 11 & 12	0.108 ¢/kwh	1.55%
Schedule 21 & 22	0.071 ¢/kwh	1.55%
Schedule 25	0.046 ¢/kwh	1.55%
Schedule 31 & 32	0.076 ¢/kwh	1.55%
Schedules 41-49 (Street Lighting)		1.55%

Natural Gas	Rider Rate	% Increase
Schedule 101	0.248 ¢therm	0.52%
Schedule 111 & 112	0.215 ¢/therm	0.52%
Schedule 121 & 122	0.189 ¢/therm	0.52%
Schedule 131 & 132	0.171 ¢/therm	0.52%

The average residential monthly electric bill would be increased by approximately 78¢ under the proposed rider. These rates would provide approximately $10.15 million to apply towards the proposed DSM programs for each of 1995 and 1996, and is approximately equal to the estimated total program costs for those two years. The proposed rate for natural gas customers is proportionately lower than the electric rider rate so as to match natural gas rider revenue with natural gas DSM expenditures. Changes to the rider rate would occur as programs and measures are revised in future filings.

The proposed rider rate does not include lost margins. Lost margins are estimated to be $846,000 based on the proposed programs contained in this application. Of every dollar collected under the rider, an additional 14.8 cents represents lost margin. While WWP believes that lost margins between rate cases is problemmatic, the company recognizes that it is its decision to not file a rate case and, therefore, is not requesting lost margins recovery herein.

E. Restrictions: Restrictions on the Rider are summarized as follows:

1. Funds may be applied only to DSM related costs approved by the Commission.

2. Unused funds would accrue interest at a rate of 10%.

3. The Rider would be reviewed during a general rate case and at such other times as the Commission may deem appropriate.

Attachment E provides the accounting guidelines for the proposed rider.

F. Customer Acceptance of the Proposed Tariff Rider: WWP has a long-standing concern regarding consumer rates. Since 1987, there has been only one change to electric base rates. Thus, development of this Rider proposal included consideration of its acceptability to customers. WWP commissioned an independent research firm, Robinson Research, to conduct a survey on issues regarding charging customers for DSM through the kind of Rider mechanism being proposed. Robinson Research surveyed 300 randomly chosen WWP residential customers between July 27 and August 1, 1994.

Eighty-three percent (83%) of the respondents said they would be willing to pay up to one dollar per month to fund energy efficiency programs available to all customers. Further, in recognition of the fact that deferrals of cost recovery are more expensive to customers in the long run than are immediate cost recovery mechanisms, customers were asked if they would prefer to pay about $1.00 now or pay between $1.50 and $1.75 in about six years from now. Sixty-nine percent (69%) said that they would prefer to pay $1.00 now.

This survey indicates that customers want the company to run DSM programs, they are willing to pay for it, they prefer to pay for it up-front rather that waiting to pay more later, and up to $1.00 per month is an acceptable amount to pay. Summary results of this survey are included in Attachment F.

G. Consistency with Merger Application: In the company's merger

VERIFICATION

STATE OF WASHINGTON)
:ss.
County of Spokane)

I, Thomas D. Dukich, being first duly sworn on oath, deposes and says: That he is the Manager - Rates and Tariff Administration of The Washington Water Power Company and makes this verification for and on its behalf of said corporation, being thereto duly authorized;

That he has read the foregoing application, knows the contents thereof, and believes tha same to be true.

Thomas D. Dukich

SIGNED AND SWORN to before me this 25th day of October, 1994, by Thomas D. Dukich

LOIS J. BEECHER COMMISSION EXPIRES NOTARY PUBLIC DECEMBER 24, 1997 STATE OF WASHINGTON

Lois J. Beecher
NOTARY PUBLIC in and for the State of Washington, residing at Spokane.
Commission Expires: 12-24-97

Att B: WPP Petition WUTC Staff Recommendation for Approval

Agenda Date: December 14, 1994
Item Number: 2B and 2C

Docket: UE-941375 and UE-941377
Company Name: Washington Water Power

Staff: Deborah Stephens, Utilities Rate Research Specialist DS
Roland Martin, Revenue Requirements Specialist

12/14/94

Recommendation:

Permit the revisions filed in Dockets UE-941375 and UE-941377 to become effective January 1, 1995, as filed.

Discussion:

Purpose:

The purpose of these filings is to revise Washington Water Power's (WWP/Company) Schedule 90, the Company's demand-side management (DSM) tariffs, and to create a special tariff (Schedule 91) which is designed as a separate charge to customers to provide funding for the DSM programs. The programs in Schedule 90 replace the Company's existing DSM tariffs, the majority of which are scheduled to "sunset" at the end of this year. The proposed programs consist of a continuation of selected existing programs and several market transformation efforts. The DSM programs in this tariff filing are being requested by the Company at a time when it contends to have no impending short-term need for these resources. The proposed "DSM tariff rider" provides for current expense treatment of DSM program expenditures, rather than traditional ratebase/amortization treatment, therefore lowering the cost of DSM to customers and avoiding the build-up of a regulatory asset by the Company.

The proposed programs include three experimental market transformation programs: a Resource Conservation Manager (RCM) program, a commercial/industrial trade ally program, and a commercial/industrial building commissioning program. The RCM program targets improved operations and maintenance within public schools. The salaries of two resource conservation managers, hired from among existing school personnel staff, will be guaranteed with the expectation that bill savings from reduced energy consumption will more than offset program costs, based on similar programs which have been run in Oregon. The trade ally program is designed to identify and implement DSM projects that are cost-effective but have not occurred because of identifiable market barriers. The building commissioning program is a process of assuring that all building facility systems perform interactively at the highest efficiency level in accordance with the owner's operational needs. These market transformation programs are consistent with a regional direction of acquiring the DSM resource at a lower cost to ratepayers.

Process:

Several discussions pertaining to issues of this filing were held by the Demand-Side Issues Group (DIG), which was established in 1992 to discuss the Company's DSM efforts. Members of the DIG discussed but did not reach consensus on an appropriate level of DSM. Several members of the DIG expressed concerns regarding the Company's resource decisions which have ultimately impacted the level of DSM. It is Staff's understanding that the DIG was never intended to be a forum for determining the Company's resource needs. Due to a lack of consensus on the appropriate level of DSM acquisition, the design and implementation of the programs proposed in this filing were not discussed within the DIG process. However, following the filing of these tariffs, Staff held a meeting to discuss the concerns of DIG members related to program design. The Company amended its tariffs based on that meeting, in order to address the concerns of DIG members who participated in Staff's meeting.

Staff's investigation of the Company's funding mechanism proposal included analysis and evaluation from an economic, policy, financial, and revenue requirement standpoint. Based on the results of Staff's investigation, concerns were addressed, discussions ensued, negotiations took place, and Staff and the Company ultimately reached a mutual agreement. It is Staff's understanding that other negotiations between the Company and several DIG members occurred but did not result in a settlement.

Considerations and Recommendations:

Staff recognizes that this filing represents a considerable ramp-down of DSM acquisition from Water Power's current level. In light of its assertion of resource balance, the Company has based its decision to offer these programs on the following objectives: the promotion of energy efficiency, the desire to maintain resource diversity, the ability to address the timing of resource needs, the interest in promoting market transformation efforts, and the creation of improved customer service. Staff finds these objectives and the proposed DSM programs to be reasonable in the face of a potentially changing electric industry environment.

Staff believes that both the magnitude of DSM acquisition and the Company's supply-side resource acquisition decisions are determinations that should be left to the Company's management, and should be examined and evaluated for prudence in a general rate proceeding. Staff takes its guidance most recently from Commission orders in Docket UE-930616, Commission Order Dismissing Complaint of Sesco, Inc., which provides the following: "Thus, the Commission has determined that it will allow utility management to determine, in the first instance, what resources it should build or purchase. The Commission, under current practice, reviews those decisions in a general rate proceeding."

The Company views its proposed DSM tariff rider as a measured response to industry changes which, among other things, does not require a general rate case to implement. However, if approved, the rider will increase customers' rates by approximately 1.5%. On average, residential customers' bills will increase by approximately 81 cents. The lack of an "earnings test" by the Company to support its proposal caused major concerns to Staff. Staff performed a review of the Company's most recent "Commission basis" results of operations. Based on the results of Staff's analysis of the Company's earnings level, Staff concluded that the incremental revenue from the tariff rider to fund the DSM programs falls within a reasonable range which may be subjected to litigation, depending on the extremity of each party's assumptions regarding fair cost of capital, capital structure, and cost of service elements.

With this traditional ratemaking parameter in mind, Staff considered the following factors and concluded that a recommendation of the revenue increase proposed by Water Power is in the public interest:

a) The revenue increase will not yield additional earnings to the Company, because the funds generated will be used exclusively for DSM acquisition.
b) Granting the rider is consistent with the provisions of RCW 80.28.260 which directs the Commission to consider granting the Company protection from a reduction in short-term earnings that may be a direct result of energy efficiency programs.
c) With the rider, the company expenses rather than defers its DSM expenditures which will avoid the build-up of a regulatory asset on the utility's books and the complexities associated with deferred accounting and AFUCE.
d) The Company has agreed to accelerate the amortization of DSM expenditures currently on its books, beginning on January 1, 1995, which will lower the cost of this DSM to ratepayers and simultaneously address the emerging issue of regulatory assets.
e) Other benefits and considerations as stated in the Company's filing.

By recommending that the Commission approve the Company's proposed DSM tariff rider for a two-year period, Staff does not make any determinations regarding the future treatment of expenditures which are incurred to acquire demand-side resources in order to meet resource needs. Nor should any party construe the Commission's acceptance of the experimental rider as an indication of any preference or policy determination regarding the appropriate method for acquiring conservation or the associated rate-making treatment of conservation expenditures.

In conclusion, Staff has considered the concerns of the other interested parties in this proceeding and believes that Commission policy dictates that resource acquisition be determined by the Company. Staff also believes that the proposed tariff rider offers a reasonable alternative to ratebase treatment of DSM expenditures. Therefore, Staff believes the proposed revisions are reasonable and recommends the Commission permit the filings in Dockets UE-941375 and UE-941377 to become effective January 1, 1995.

Att C: Opinion and Order Regarding Flexible Rates, No. 94-15, Case 93-M-0229 (July 11, 1994), p. 31 ¶ 5 (excerpt)

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

OPINION NO. 94-15

CASE 93-M-0229 - Proceeding on Motion of the Commission to Address Competitive Opportunities Available to Customers of Electric and Gas Service and to Develop Criteria for Utility Responses.

OPINION AND ORDER REGARDING FLEXIBLE RATES

Issued and Effective: July 11, 1994

Guidelines on Flexible Rates

The foregoing discussion leads to the adoption of the following general guidelines for flexible rates:

1. The intent of flexible rates for electric customers is to maintain contestable customers on the utilities' systems, in a way that benefits all ratepayers.

2. Flexible rates should be available for electric customers who have realistic competitive alternatives. A utility is not mandated to offer such rates if, in the utility's judgment, the rates would not be advantageous to the utility's customers as a whole.

3. The tariffs in place for Niagara Mohawk, NYSEG, and RG&E should serve as models for flexible rates. Appendix B summarizes the main provisions of each of these tariffs.

4. The loss of revenues due to discounts should be shared between shareholders and ratepayers. The extent and manner of sharing will be determined in the context of individual rate cases.

5. Independent and comprehensive DSM audits are required in conjunction with the offering of flexible rates, but there will be a flexible approach to implementation.

6. The potential cost to the customer of complying with environmental regulations sufficient to meet minimum environmental permitting requirements will be taken into consideration when determining whether a customer has a realistic competitive alternative.

7. A floor price for flexible rates will be calculated by each utility, and will generally be set at no lower than the marginal cost of service to the customer plus 1¢/kWh.

8. Prices in contracts for flexible rates generally will not be fixed for longer than a seven-year period, unless a longer term is approved by the Commission in response to a utility's petition.

9. Utilities offering flexible rates must file quarterly reports on the use of these rates, including information about the number of contracts, amount of load, percentage of discounts, effect of DSM audits, and environmental considerations as they relate to the feasibility of competitive alternatives with regard to the acquisition of needed environmental permits (referred to in guideline 6 above). Staff will analyze these reports and provide regular updates to the Commission.

FUTURE ISSUES TO BE ADDRESSED

The staff report did not address the scope of a possible second phase of this proceeding: an investigation into the appropriate market structure and regulatory regime for the future. However, at the on-the-record forum and in their comments, the parties presented various options for the scope of a second phase of this proceeding. The comments ranged from seeing no need for an investigation at this time to welcoming an open-ended investigation into all types of competition, both wholesale and retail.

The utilities offer mixed support for a Commission investigation. Niagara Mohawk sees a need for clear guidelines and fair rules. LILCO expresses its concerns about a retail

Att D: Application of Washington Water Power, Case No.'s WWP-E-94-10, WWP-G-94-5, Order No. 25917 (Idaho PUC Mar. 6, 1995) (Sierra Club Att. D).

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF THE WASHINGTON WATER POWER COMPANY FOR APPROVAL OF REVISED GAS AND ELECTRIC TARIFFS FOR IMPLEMENTATION OF ENERGY EFFICIENCY PROGRAMS FOR RESIDENTIAL, COMMERCIAL AND INDUSTRIAL CUSTOMERS.	)	CASE NOS. WWP-E-94-10 WWP-G-94-5 ORDER NO. 25917

On October 26, 1994, The Washington Water Power Company (WWP) filed an Application requesting approval of tariff revisions related to demand side management (DSM) or conservation programs, as contained in Schedules 90 and 190, and including proposed new Schedules 91 and 191. At WWP's request, the process for approval of the DSM programs (Schedules 90 and 190) and the new proposed Schedules 91 and 191 was bifurcated. By Order No. 25841 issued in Case No. WWP-E-94-12/WWP-G-94-6, the Commission approved the DSM programs for 1995 and 1996 as contained in revised Schedules 90 and 190.

Schedules 91 and 191 are proposed tariff riders which would increase retail electric and natural gas energy rates by approximately 1.55% and 0.6%, respectively, to pay for DSM programs during 1995 and 1996. The proposed rate for natural gas customers is lower because DSM expenditures for natural gas programs are lower than for electric programs. The tariff riders would provide funding for specific DSM programs through a separate tariff rate assessed on energy transmitted over WWP's distribution system, and would apply to all retail energy sales for all customer classes except special contract customers and electric customers in the Sandpoint, Idaho area. Sandpoint customers are excluded from a rate increase as a result of WWP's purchase of PacifiCorp's Sandpoint service territory.

WWP's Application regarding the proposed tariff rider contained in Schedules 91 and 191 was set for hearing on February 14, 1995. Staff notified the Commission and the intervenors on January 20, 1995 that it would attempt to resolve its concerns regarding Schedules 91 and 191 by settlement negotiations which, if successful, would eliminate the need for a hearing. Staff and WWP did negotiate revisions to the tariff rider, resulting in a Settlement Stipulation by the

Commission Staff and The Washington Water Power Company (Settlement Stipulation) The Settlement Stipulation was filed February 7, 1995.

On February 13, 1995, the Commission issued a Notice of Hearing Cancellation and Notice of Modified Procedure informing interested individuals and parties that written comments regarding the proposed tariff rider and the Settlement Stipulation could be filed with the Commission through February 27, 1995. Written comments were received from two different WWP residential customers, one located in Clarkston, Washington and the other in Moscow, Idaho. The Clarkston customer expressed "opposition to any WWP rate increase" and, opining that WWP executives are paid excessively, stated that "executive salaries could be cut by 80%." The Moscow customer is a retired couple who feels that WWP's charges already "are much too high." The customer's home is all electric and cannot easily be converted to gas heat. The Moscow customer suggested that "some provision should be made for homes built before gas usage was encouraged," and also stated that a large bonus WWP paid its chairman does not benefit ratepayers.

No other comments were filed with the Commission. Staff recommends approval of the tariff rider set forth in Schedules 91 and 191 as modified by the terms of the Settlement Stipulation.

FINDINGS OF FACT AND CONCLUSIONS OF LAW

Having reviewed the complete record in this case, we find WWP's proposal to fund demand side management programs during 1995 and 1996 by a tariff rider to be reasonable and in the public interest. Traditionally, a utility defers the costs of its DSM programs and then recovers its expenditures in a general rate proceeding when accumulated DSM expenditures, plus interest (accrued as an allowance for funds used during construction—AFUDC), become a component of rate base. During the lag between the time the DSM expenditures are incurred and their recovery, the utility is allowed to record on its books a "regulatory asset," indicating the company will be permitted to recover its accrued, prudently incurred costs through future rates. The accrual over time of DSM expenses plus interest may result in a total accrual that is a significant amount, thus having a sizable affect on future rates when the accrued amount is included rate base. Additionally, the Commission's ability to evaluate the effectiveness of a particular DSM program during a general rate case is limited where significant time may have lapsed since completion of the program. The two year tariff rider approved in this case will provide an opportunity to evaluate an alternative accounting method that may benefit both WWP and its ratepayers. The Company will be able to timely recover its costs, and the indefinite accumulation of a sizeable balance to be recovered through future rates will be avoided, thus minimizing rate shock in the future.

We also find the Settlement Stipulation proposed by Staff and WWP to be reasonable, in the public interest, and consistent with regulatory policy. The Stipulation provides, among other things, for on-going evaluation of the DSM programs and reporting to Staff. WWP also assumes the risk of under-collecting by the rates in the tariff rider so that the rates cannot go up during the two years it is in effect, but may go down if the tariff rider results in an over collection. We hereby approve the Settlement Stipulation and adopt its terms to govern the tariff rider while it is in effect during 1995 and 1996.

The Washington Water Power Company is an electic and gas public utility subject to the Commission's regulation under the Idaho Public Utilities Law, Title 61, *Idaho Code*. This Commission has jurisdiction and authority to determine rates and charges for WWP's services pursuant to the Idaho Pubic Utilities Law, and in particular *Idaho Code* §§ 61-502 and 61-503.

O R D E R

IT IS HEREBY ORDERED that the Application of The Washington Water Power Company for approval of proposed tariff Schedules 91 and 191 implementing a tariff rider for recovery of the Company's 1995 and 1996 demand side managment expenses is hereby granted, subject to the Settlement Stipulation and the terms and conditions set forth in the text of this Order. WWP is directed to file tariff Schedules 91 and 191 consistent with this Order, to be effective seven days after the date of filing.

THIS IS A FINAL ORDER. Any person interested in this Order (or in issues finally decided by this Order) or in interlocutory Orders previously issued in these Case Nos. WWP-E-94-10 and WWP-G-94-5 may petition for reconsideration within twenty-one (21) days of the service date of this Order with regard to any matter decided in this Order or in interlocutory Orders previously issued in these Case Nos. WWP-E-94-10 and WWP-G-94-5.

Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. See *Idaho Code* § 61-626.

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 6th day of March 1995.

MARSHA H. SMITH, PRESIDENT

RALPH NELSON, COMMISSIONER

DENNIS S. HANSEN, COMMISSIONER

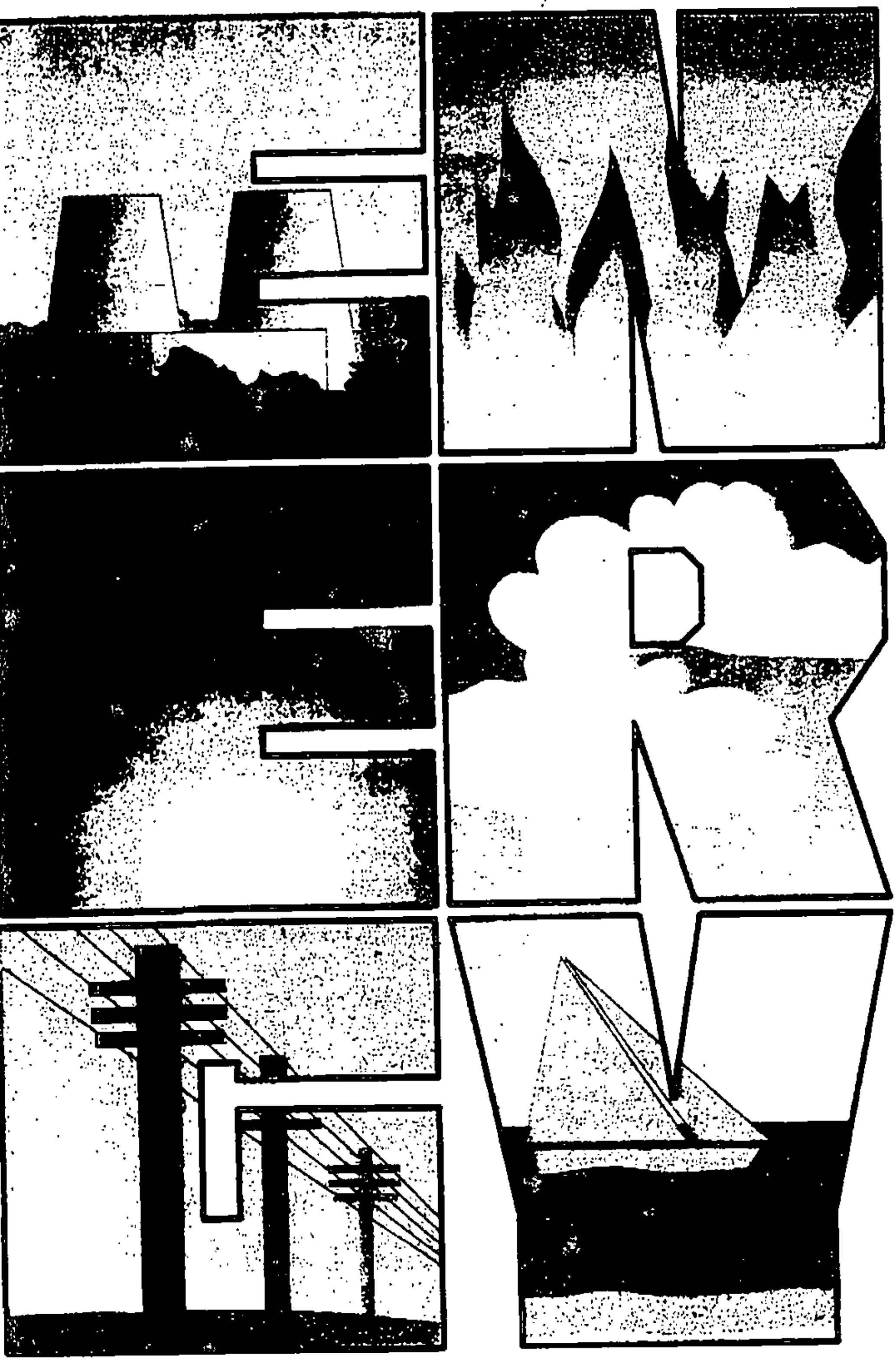
ATTEST:

Myrna J. Walters
Commission Secretary

vld/O-WWP-E-94-10.ws

Att E: New Jersey Energy Master Plan (March 1995), p. 26 (excerpt)

New Jersey



Master Plan

PHASE I REPORT • MARCH 1995

new construction;
- allowing the native utility to bid in its service territory;
- providing for the Board of Public utilities to act as judge if the native utility is proposing a project; and
- providing for auditing procedures to ensure no cross-subsidization.

▲The Board of Public Utilities should draft proposed legislation which repeals the Electric Facilities Need Assessment Act and replaces it with a requirement that the Board adopt policies which maintain the public policy objectives of the Act, including a determination that the proposed facility is necessary to meet the projected need for electricity in the area to be served and that no more efficient, economical or environmentally sound alternative is available. Any proposed legislation should also include a requirement that the Board of Public Utilities' policies continue to address the conflict of interest issue. The repeal of the Electric Facilities Need Assessment Act must be timed to coincide with the adoption of IRP rules and the competitive supply-side procurement process to ensure that there is no gap in maintaining the public policy objectives of the Act and to prevent duplicative review processes.

Rate Flexibility and Alternative Regulation

Certain retail customers of the State's regulated natural gas and electric utilities have, to varying degrees, choices concerning their source of gas or electric. The Board of Public Utilities' natural gas unbundling order, previously described, allows the State's commercial and industrial customers to purchase gas from other than the local distribution company. While the retail electric markets have not yet been restructured in a manner similar to the natural gas markets, electric utilities do face competition for retail customers.

Perhaps the most direct form of electric retail competition is on-site generation. The best-known example of this phenomenon is the construction by a third party of an unregulated cogeneration facility at the site of a large industrial customer, with the facility serving as the primary source of electricity and process steam for the manufacturing entity. Thereby, retail electric sales can be lost to the local electric utility, and Gross Receipts and Franchise Tax (GRFT) revenues lost to the State and, ultimately, to the State's municipalities. Such arrangements are attractive at energy-intensive manufacturing facilities, where the host industrial customer can significantly reduce its operating costs and the nonutility generator can sell enough power and steam to realize an acceptable return on investment.

Other than on-site generation, the principal competitive threat currently facing the electric utilities is that of business relocation or curtailment. To wit, the retail electricity prices and other costs of doing business in New Jersey are higher relative to many neighboring states, and even more so when the comparison is expanded nationwide. As such, the specific threat facing the State's utilities is that businesses in New Jersey can and do relocate to other states or even overseas where power is less expensive, or shift production from in-state facilities to out-of-state plants. In this global economy, power costs can be a key, contributing or merely incidental variable in such decisions. Of course, for most residential customers and many business customers, on-site generation or relocation in order to garner less expensive electricity prices is neither feasible nor practical.

Due in part to the accelerating globalization of the economy and slower world economic growth, U.S. industry, as well as other business sectors, have come under a heightened degree of competitive pressure. Demands by energy-intensive manufacturers for lower energy prices in an attempt to reduce production costs have created pressures for new ways to accommodate these demands. Rate flexibility, whereby prices are set more on a market-driven basis rather than the traditional average embedded cost-of-service approach, is one tool which has been applied recently to address competitive concerns and enhance the State's economic development goals. In a number of states, such as California and Michigan, retail wheeling and other programs are being explored as a means of addressing the demands of business for less expensive electricity. Under a retail wheeling program, retail customers would have a multitude of suppliers of electric power generation to choose from, similar to the structure which has in recent years emerged on the wholesale level and in the natural gas industry. Such a scheme would subject electric utilities to a much greater degree of direct competition for the sale of electric generation to their retail customers.

Given the somewhat limited, but growing, retail competition already being faced by the natural gas and electric utilities industry, and the prospect of heightened competition and perhaps retail wheeling on the horizon as business and economic development pressures mount, the financial rating agencies have already begun re-evaluating the degree of business and regulatory risk to which utilities are exposed. This re-evaluation has resulted in lower financial ratings for many gas and electric utilities. Some of the key factors which can negatively impact the perceived future financial performance of an electric utility are high-cost production, a large proportion of industrial loads that are targeted by competitors, high-cost excess capacity, uneconomic plant investment and high-cost power purchase contracts. The specific cause for the potential devaluation of many utilities in the face of heightened competition is the difference between the actual generation costs of a particular utility and the market price for power. Unfortunately, due to a number of economic and environmental factors, New Jersey's electric utilities generally do not fare well in such a comparison due to relatively high production costs. This should be cause for some concern and careful thought as the State considers how to best address the emerging competition issues. Moreover, it is expected that nearby states which currently enjoy lower energy costs, in part due to less stringent environmental emissions standards, will also be implementing policies to assist their utilities and businesses to compete with New Jersey's.

It is expected that over time, the unleashing of the competitive forces in the wholesale power market, as furthered by the proposed IRP/Supply-Side model, will gradually bring down the average electric production costs experienced by the State's utilities. This, in turn, should assist the utilities to control their retail prices and otherwise become more competitive in the retail marketplace.

However, these changes and benefits are not expected to occur overnight. The immediate question is what the State and its utilities can do in the short term to permit the State's utilities the flexibility to compete for their at-risk customers and otherwise offer pricing incentives to promote economic development, while at the same time providing utilities with incentives to control and reduce their costs and rates in order to become more competitive.

Rate Flexibility

Over the past two years, as a result of individual competitive threats or in response to economic development concerns, the Board of Public Utilities has approved a number of tariffs or service agreements which have effectuated or created the opportunity for price discounts for individual customers. Such actions include the New Jersey Steel service agreement, the Bayway refinery contract, and the economic development tariffs for the State's electric and gas utilities. Even more recently, in January 1995, the BPU approved JCP&L's request for rate flexibility in order to implement discounts for its high-volume, residential electric heating customers. Such initiatives have been adopted by the Board of Public Utilities on a case-by-case basis, after extensive and time-consuming regulatory reviews.

While these actions have been taken under current law as embodied in Title 48, several concerns have arisen which question the ability of the utilities and the regulatory process to react in a timely fashion to competitive threats and emerging economic development opportunities. Specifically, while the Board of Public Utilities has asserted its ability to approve such tariffs or service agreements under current law, the continued prospect of legal challenges to that ability casts a cloud over such transactions. Specific enabling legislation will dispel any uncertainty and facilitate the execution of such transactions, ultimately benefiting the State's economic development, as well as the utilities and their customers.

It is therefore appropriate that the Board of Public Utilities develop and propose such enabling legislation to specifically permit the Board of Public Utilities to approve the implementation of rate flexibility by electric and gas utilities. Such legislation will include or provide for the establishment by the Board of Public Utilities of standards to govern such rate flexibility programs. In this manner, all parties will know in advance the conditions for the offering of price discounts and, subject to meeting the prescribed standards, utilities will be able to swiftly negotiate and effectuate such transactions without awaiting the results of a lengthy and complex regulatory review.

A critical issue with respect to the adoption of rate flexibility standards is a policy with respect to the treatment of so-called "lost revenues" resulting from the implementation of price discounts. Lost revenues are generally defined as the difference between the revenues collected from a customer under the discounted price and that which would have been collected at the tariffed, full cost-of-service price. The Board of Public Utilities has generally adopted an approach that lost revenues should not be recovered from other ratepayers, at least until the conclusion of the utility's next base rate case, and should not be subject to deferred accounting. Such an approach is founded on sound ratemaking principles and should be the policy of the State and be embodied in the enabling legislation.

The next issue concerns prospective treatment of such lost revenues at the conclusion of base rate cases. This issue has purposely not been addressed by the Board of Public Utilities during past proceedings, pending the development of a comprehensive rate flexibility and energy policy. Within the context of this document, and resultant implementation steps, such policy can now be developed.

The State should, via enabling legislation, establish standards to govern rate flexibility programs. The standards should include two tiers. The first tier would include the minimum standards that must be met by a utility to implement a discount, whether or not it proposes the recovery of lost revenues from other customers. A second tier of standards would need to be established for application should a utility request to recover a portion of the lost revenues from other customers.

To that end, the Board of Public Utilities should consider including the following standards in its draft Rate Flexibility legislation which must be met by a utility whether or not it proposes the recovery of lost revenues from other customers:

1. a prohibition against any recovery by the utility of the revenue erosion which results from the discount prior to the conclusion of the utility's next base rate case;
2. a requirement that the negotiated rate discount must equal or exceed a minimum, prespecified floor price;
3. a requirement that the duration of the negotiated rate discount agreement not exceed a maximum, prespecified contract term; and
4. a requirement that the customer granted the rate discount have a comprehensive energy audit performed at its site. The energy audit would be considered confidential and if performed at the expense of the utility, should be considered a reasonable utility DSM expenditure for ratemaking purposes.

The Board of Public Utilities should develop the specific implementing details of the standards such as the components of the floor price and the maximum contract term, as well as the reporting requirements which should include at a minimum, the number of rate discounts granted, the dollar amount of the discounts and the aggregate dollar amount of all rate discounts granted. The Board of Public Utilities, in its review of the information filed, should evaluate the aggregate impact of all individual rate discount agreements on the financial integrity of the utility and its ratepayers.

As indicated previously, utilities should be provided an opportunity to recover a portion of revenues lost as the result of rate discounts on a prospective basis at the conclusion of base rate cases. The Board of Public Utilities should consider that such recovery only be permitted if a utility can demonstrate in its base rate case, at a minimum, that:

1. the customer had a viable competitive alternative and the price discount was necessary to prevent a customer from leaving the utility system or relocating operations, or that the price discount induced the customer to relocate to or expand its business in the State;
2. all appropriate offsetting financial adjustments are credited to the revenue requirement associated with that particular base rate case;
3. other ratepayers benefit by the discount having been implemented as compared to had the discount not been implemented, and that cross-subsidization via an inappropriate shift in cost responsibility between customers does not otherwise occur; and
4. the utility has implemented a corporate strategy to reduce its overall level of costs. Importantly, the enabling legislation should provide utilities with the flexibility to act quickly and at their discretion in the offering of individual rate discounts. Provided that the tier one implementation standards are met, no specific regulatory approvals would be required. However, in implementing a rate discount, utilities will bear the risk for meeting the second tier of standards necessary to receive future rate recovery of lost revenues.

It is important to emphasize that, even if it meets the established rate recovery standards, a utility should only be entitled to recover a portion of the lost revenues. In this manner, a strong incentive will be created for the utility to reduce its costs as a primary long-term means of addressing competitive threats, consistent with the overall energy policy goals of the State as described throughout this document.

It is worth noting that there are significant differences in the current evolution of market structure between the electric and natural gas industries. Moreover, the nature of retail pricing in the two industries, including the parity pricing and margin sharing concepts for gas utilities, is different in many respects. As such, in drafting specific proposed legislation, the Board of Public Utilities will consider whether there is a similar need for specific revisions of law in both the gas and electric industries and, whether different rate flexibility standards for the gas utilities than those enunciated above are appropriate.

Alternative Regulation

There has been substantial recent debate both within the State and nationwide concerning whether the traditional rate-base/rate-of-return mode of regulation continues to best serve the public interest in the face of the fundamental changes sweeping the electric and gas industries. At their core, the current Title 48's regulatory standards, the origin of which can be traced back some eighty years, presume the monopoly provision of electric and gas services and base the potential for earnings growth by the utility on the expansion of the rate base, that is, on new plant investments.

As previously discussed, competition in the gas industry now exists virtually from the wellhead to the burner tip. In the electric industry, the generation end of the business is now subject to substantial competition, and some end users are beginning to be presented with choices in terms of source of supply. With market forces increasingly prevalent in many industry segments, it is questionable whether the application of traditional, cost-based regulation standards provides sufficient flexibility and imparts effective incentives to improve productivity and efficiency, reduce costs and encourage appropriate investments.

A number of alternative regulatory schemes, including price caps, revenue sharing, performance-based rates and pricing flexibility, are possible means of more appropriately aligning regulatory practices with the changing nature of the electric and gas industries. In fact, some of these measures, particularly performance-based rate regulation, have already been implemented in a number of states. Indeed, the New Jersey Board of Public Utilities has instituted a number of limited incentive mechanisms, including nuclear performance standards and DSM incentive regulations.

Given the rapidly changing landscape in the gas and electric industries, it is appropriate to provide sufficient flexibility in the regulatory system to allow the Board of Public Utilities to entertain and, if deemed in the public interest, approve alternative forms of regulation. Indeed, the proposed competitive supply-side procurement model might necessitate a ratemaking mechanism other than traditional rate-base/rate-of-return to provide for a meaningful comparison of competing projects.

As such, the Board of Public Utilities will develop and propose alternative regulation legislation which will allow gas and electric utilities to petition the Board of Public Utilities to consider plans for alternative forms of regulation.

It must be emphasized, however, that many segments of the utilities' customer base remain essentially captive to their local utility under the current industry structure. These customers remain reliant on the strong regulatory oversight envisioned in the current Title 48 statute to ensure that they receive safe and reliable utility service at fair and reasonable prices.

It is for this reason that any immediate alternative regulation legislation must be fashioned as a supplement to, rather than a replacement for, the current statutes. It is essential that the legislation create incentives and opportunities for utilities to reduce costs, maintain and improve service quality, promote economic development, be rewarded for accepting higher risks and foster cost-effective energy efficiency and environmental compliance, while at the same time continue the fundamental protection of the captive customer embodied in Title 48.

In order to accomplish this important balance, and in recognition that no specific proposals for alternative regulation have yet been presented for evaluation, it is imperative that the alternative regulation legislation contain specific standards for acceptability of proposed plans. Specifically, the Board of Public Utilities should consider including the following standards in its proposed legislation for approval of a plan for alternative regulation:

1. the plan will produce tangible benefits for the customers of the utility relative to the existing form of regulation;

Att F: N.J. Senate Bill S-1940 § 3.c(4), p. 3 (Proposed 1995) (excerpt)

S-1940

AN ACT concerning public gas and electric utility rates and supplementing chapter 2 of Title 48 of the Revised Statutes.

BE IT ENACTED *by the Senate and General Assembly of the State of New Jersey:*

1. The Legislature finds and declares that it is the policy of the State to foster the production and delivery of electricity and natural gas in such a manner as to lower costs and rates and improve the quality and choices of service for all of the State's consumers and to thereby ensure that New Jersey remains economically competitive on a regional, national and international basis; to implement programs which effectuate the economic development goals of attracting and retaining business, maintaining and creating jobs and enhancing the economic vitality of the State; to achieve federal and State environmental objectives in a cost effective manner; to promote secure energy supplies and service to end users, and the efficient use, production and procurement of energy; to maintain universal access to reliable electric and gas utility service; and to reduce unnecessary and costly regulatory oversight.

The Legislature further finds and declares that competitive market forces can produce improved quality and choices of energy services at lower costs, as well as promote efficiency, reduce regulatory delay, foster productivity and innovation; that in a fully competitive marketplace, traditional utility regulation may not be required to protect the public interest; and that to varying degrees, competitive forces now pervade the wholesale electric power and natural gas markets and some segments of the retail markets in these industries.

The Legislature therefore determines that, whenever practicable, in the interests of ratepayers and otherwise consistent with the policy goals of this act, the Board of Public Utilities should implement programs that promote a transition to a market-based, competitive environment for the production and delivery of natural gas and electricity; that during a transitional phase aimed at achieving the long-term goal of lower electricity and natural gas costs to consumers, it may be necessary for the Board of Public Utilities to implement short-term measures to promote and enhance economic development and employment in the State and otherwise permit utilities to compete for customers with competitive alternatives, that transitional programs that align ratepayer and utility interests in cost management and foster greater innovation and productivity gains within the utility can help achieve the policy goals of this act; that during the transition to a market-based, competitive environment, the Board of Public Utilities must adopt guidelines that ensure that the transitional regulation produces tangible benefits for ratepayers as compared to the traditional form of regulation and that no cross-subsidization exists between or among classes of customers; and that the Board of Public Utilities should, subject to the provisions of this act, continue to regulate the price and quality of electricity and natural gas service under traditional rate base rate of return regulation in those segments of the marketplace where full and effective competition does not exist or whenever the board determines that energy consumers are better served thereby.

2. As used in this act:

"Alternate form of regulation" means a form of regulation of electric or gas utility services other than traditional rate base, rate of return regulation as embodied in Title 48 of the Revised Statutes, to be determined by the board;

"Board" means the Board of Public Utilities or any successor agency;

"Competitive market" means a market for a particular utility service that is characterized by the existence of a number of purveyors, the availability of like or substitute service, ease of market entry, and such other standards as may be adopted by the board;

"Comprehensive energy audit" means an assessment of all energy-using systems to determine the consumption characteristics of a building. The assessment (1) identifies the type, size, and rate of energy consumption of such building, including industrial processes in the building, (2) determines appropriate energy conservation maintenance and operating procedures; and (3) indicates the need, if any, for the acquisition and installation of energy conservation measures;

"Cross subsidization" means an undue transfer of cost allocation or revenue recovery responsibility;

"Demand Side Management" means the management of a public utility's existing or future capacity or energy needs through the implementation of cost-effective energy efficiency technologies, including, but not limited to, installed conservation, load management and energy efficiency measures in the residential, commercial, industrial institutional and governmental premises and facilities in the State.

"Discount rate" means a rate for utility service charged by a utility to a retail customer that is the result of a negotiation between the utility and the customer, rather than being based solely on a cost-of-service based tariff rate;

"Marginal energy and capacity cost" means the incremental increase in a utility's energy and capacity costs associated with providing an additional increment of utility service, over a specified time period;

"Market pricing" means charging a negotiated price for utility service which is based upon the price available in a competitive marketplace, as opposed to a cost-of-service based tariff rate; and

"Revenue erosion" means a reduction in revenues received by the utility resulting from the provisions of a discount rate to a customer, as measured by the difference between the cost-of-service based tariff rate and the discount rate, multiplied by the sales to that customer.

3. a. No later than 45 days from the effective date of this act, the Board of Public Utilities shall initiate a proceeding and shall adopt, after notice and provision of the opportunity for comment, specific standards regarding floor prices and margins, maximum contract duration, filing requirements, and such other standards as the board may determine are necessary for discount rate agreements consistent with this act.

b. After the adoption by the board of specific standards pursuant to subsection a. of this section, an electric public utility may negotiate a discount rate agreement with an individual retail customer. The discount rate agreement shall be filed with the board on a confidential basis a minimum of 15 business days prior to its effective date along with sufficient information to demonstrate that the discount rate agreement meets the conditions established in subsection c. of this section and the standards established pursuant to subsection a. of this section. The board may disapprove the agreement upon a finding that it does not meet the conditions established in subsection c. of this section and the standards established pursuant to subsection a. of this section. If the board does not disapprove the agreement prior to its effective date, the utility may implement the discount rate agreement.

c. Upon application by an electric public utility, the board may permit and the utility may implement, via a tariff or service agreement, a discount rate that provides a price for electricity to a retail customer that is different from, but in no case higher than, that specified in the utility's current cost-of-service based tariff rate otherwise applicable to that customer, subject to the following conditions:

(1) There shall be no recovery by the utility from its general ratepayer base of revenue erosion prior to the conclusion of the utility's next base rate case. Subsequent to the conclusion of the utility's next base rate case, any such recovery shall be prospective only and in accordance with subsection f. of this section.

(2) In no event shall any customer be required to enter into a discount rate agreement.

(3) The discount rate at a minimum shall equal the sum of the following: the utility's marginal energy and capacity cost over the term of the discount rate agreement, the per kilowatt contribution to demand side management program costs as otherwise chargeable under the standard applicable rate schedule, and a floor margin to be specified by the board pursuant to subsection a. of this section.

(4) Evidence of a comprehensive energy audit of the customer facility must be submitted to the utility prior to the effective date of the discount rate agreement.

(5) The term of the discount rate agreement shall not exceed a maximum number of years, to be specified by the board pursuant to subsection a. of this section, except that the term of a discount rate agreement may exceed the maximum contract term established by the board, only with the prior review and approval of the board on a case by case basis.

(6) Submission of information required by the filing requirements established pursuant to subsection a. of this section.

d. Upon notice and hearing, the board may suspend an electric public utility's implementation of additional discount rate agreements with good cause. The board may suspend additional discount rate agreements during the pendency of any such hearings.

e. Each electric public utility shall file with the board, on a periodic basis to be determined by the board, a report that includes the number of discount rate contracts effectuated, the aggregate expected revenues and margins derived thereunder, and an estimate of the aggregate differential between the revenues produced under the discount rate agreements and the revenues that would have been produced under a cost-of-service based tariff rate, so that the board can evaluate the total impact of discount rate agreements on the financial integrity of the utility and on its ratepayers.

f. As part of a base rate case proceeding, an electric public utility may request and the board may approve prospective recovery of a portion of quantifiable revenue erosions resulting from existing discount rate agreements. The board may approve such prospective recovery, for up to 80 percent of the revenue erosion, if the board determines that:

(1) All appropriate offsetting financial adjustments, including but not limited to sales growth, standby and backup sales to the customer, and off-system capacity sales, are credited to the revenue requirement calculation;

(2) The utility has developed and implemented a corporate strategy to lower its cost of producing and delivering power;

(3) Economic and financial analyses show that ratepayers will be paying lower rates with the implementation of a discount rate agreement for a particular customer than without such implementation, or that the State will receive other tangible economic benefits as a result of a discount rate agreement. This determination shall be based on a demonstration, at a minimum, that:

(a) The customer had a viable alternative source of supply deliverable to its site; or

(b) The offering of the discount rate was a factor in inducing the customer not to relocate its facility outside of the State to a location where power could be obtained as a lower cost; or

(c) The discount rate was a factor in inducing the customer to relocate or expand its business in the service territory, thereby protecting or enhancing employment in the State; and

(4) The utility and the customer have otherwise complied with the provisions of this act and the discount rate standards adopted by the board pursuant to subsection a. of this section.

4. a. An electric or gas public utility may petition the Board of Public Utilities to be regulated under an alternative form of regulation, for the setting of prices for all or a portion of its retail customer base, for the recovery in rates of a particular asset or expenditure, or for the purpose of creating incentives consistent with the provisions of this act. The public utility shall submit its plan for an alternative form of regulation with its petition. The public utility shall also file its petition and plan concurrently with the Director of the Division of the Ratepayer Advocate, or its successor. The public utility shall provide, within 15 days of the filing of its petition and plan, public notice of the filing in a form and scope of distribution deemed appropriate by the board. The board shall review the plan and may approve the plan, or approve with modifications if it finds, after notice and hearing, that the plan:

(1) Will be consistent with the goals and provisions of this act, and produce tangible benefits for the customers of the utility relative to the pre-existing regulatory standards embodied in Title 48 of the Revised Statutes;

Att G: Excluded testimony of Bruce Biewald on DSM Cost Recovery

2. SUMMARY AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. My primary conclusions and recommendations are summarized as follows:

Financial Incentives for DSM - Conclusions

1. Financial incentives for DSM are important to overcome the many economic and institutional barriers to utility DSM.

2. Three general criteria should be used in designing successful DSM incentives: (a) the incentives should make the utility's least-cost plan its most profitable plan, (b) the impacts of the incentive should be large enough to capture the attention of management and stockholders, while maintaining acceptable rate impacts, and (c) the incentive should be simple, understandable, and easy to administer.

3. A variety of mechanisms are available, including shared savings, bounty and bonus mechanisms. Shared savings schemes offer the greatest advantages in terms of encouraging utilities to maximize DSM savings while minimizing program costs.

4. There are two distinct approaches to recovering DSM incentives: a base rate adjustment and an annual surcharge. DSM incentives that are recovered through surcharges are more effective than base rate adjustments, because they are less risky to the utility and they provide incentives that are more closely correlated to the timing of the DSM planning and implementation.

5. I understand that, in the recent DSM Cost Recovery orders of December, 1993, and April, 1994, the Commission established performance-based financial incentives for DSM programs. However, I also understand that the Commonwealth Court's January 9, 1995, Opinion and Order denied surcharge-based recovery of incentives. I also am aware that the Commission appealed the Commonwealth Court Order in an April 6, 1995, filing with the Pennsylvania Supreme Court.

Financial Incentives for DSM - Recommendations

1. If the Pennsylvania Supreme Court ultimately allows it, I recommend that utilities should be allowed the option of recovering DSM financial incentives through a surcharge.

2. The Commission should provide for the recovery of PP&L lost revenues through base rates, in accordance with the Commonwealth Court's order on this topic. Utilities should also be allowed special rate relief to make annual adjustments to lost revenue recovery to reflect actual DSM savings achieved.

3. The Commission should grant PP&L annual recovery of all net lost revenues if the Company meets 60 percent of its overall DSM savings goal based on its pre-approved DSM Plan. Otherwise, no recovery should be allowed by the Commission.

4. Separately, the Commission should establish in a remand docket the generic treatment for NLRAs for DSM, presumably consistent with that provided here.

5. The process for estimating and verifying lost revenues should be based on program participation, and not on a strict ex post approach.

. . . .

3. DSM: INCENTIVES FOR DSM

The Case for Financial Incentives

Q. IN YOUR OPINION, IS IT DESIRABLE TO HAVE FINANCIAL INCENTIVES FOR DSM?

A. Yes. I believe it is important to have an incentive based on the Company's performance in developing demand-side management opportunities.

Q. WHAT ARE THE REASONS FOR INTRODUCING AN INCENTIVE MECHANISM?

A. A utility's successful implementation of a least-cost plan should be its most financially attractive course of action. The existence of powerful economic and institutional barriers to DSM provides the first reason for financial incentives. Some of these barriers are due to the very nature of demand-side resources. Unlike power plants and transmission lines, a demand-side resource consists mostly of investment in the efficiency of the equipment owned and used by the utility's customers. For example, utility investments may be in efficient refrigerators, motors or fluorescent light bulbs, or in improved insulation. These are on the customer side of the meter. Thus, DSM changes the very nature of utility investment. This change in ownership creates disincentives for the utility, as I will explain below.

The second reason is that it is necessary to induce changes in the "corporate culture" of many utilities, one which has traditionally favored supply-side construction projects. Construction of supply-side resource additions may create financial stresses and strains for a utility. However, in the long run, construction projects are traditionally seen as the additions to rate base on which a utility earns a return for its shareholders. DSM does not provide the same opportunities for additions to rate base, and therefore, it will take an incentive to make DSM as attractive and profitable as the successful addition of supply-side resources.

The third reason is to reward a utility for achievement. A utility which performs admirably in providing DSM programs which reduce total costs should be rewarded.

Q. WHY IS IT IMPORTANT THAT UTILITIES BE ENTHUSIASTIC SUPPORTERS OF DSM?

A. Traditionally, regulators have felt that they could use a "command and control" approach to ensure that utilities make good on their responsibility to provide safe, reliable service at least cost. While command and control is still important, its usefulness is more limited than it has been in the past, for two main reasons:

2. If a surcharge cannot be used to recover DSM financial incentives, then in future rate cases the Commission should establish a base rate adjustment which provides PP&L with a financial incentive for DSM savings achieved within the test year.

3. DSM financial incentives should be calculated on the basis of shared savings, where "savings" equal the difference between long-run avoided costs and utility DSM program costs. Fifteen percent of these savings would provide an appropriate level of incentive to the utility. A system could also be designed to use a near-term measure of savings value, such as the price of off-system sales.

4. PP&L should only be allowed to recover a financial incentive once it has achieved 60 percent of its overall DSM savings goal based on its pre-approved DSM Plan.

Recovery of Net Lost Revenues from DSM - Conclusions

1. Failure to recover lost revenues from successful DSM programs creates a significant financial disincentive for utility DSM programs.

2. Regulatory commissions in at least 21 states have established various mechanisms to allow utilities to recover lost revenues. In general, utilities that are provided net lost revenue adjustments (NLRAs) have implemented more successful and more aggressive DSM programs.

3. The three primary conditions for a successful NLRA are: (a) avoiding a strict "ex post" approach to DSM measurement, (b) involving stakeholders in the NLRA establishment and measurement process, and (c) setting conditions for lost revenue recovery related directly to DSM program operation and performance.

4. I am aware that the Commission has accepted the principle of NLRAs in its 1993 DSM Cost Recovery Order. However, as I understand it, the Commonwealth Court remanded the Commission's order for the calculation methodology of lost revenues.

5. The calculation of lost revenues is relatively straightforward. There are three basic steps involved: (a) the Commission establishes a protocol for measuring the DSM savings, (b) the fixed cost component of retail rates is determined, and (c) for each rate class the fixed cost percentage is multiplied by the total DSM savings to determine total net lost revenue.

Recovery of Net Lost Revenues from DSM - Recommendations

1. As provided in the DSM Cost Recovery case, the Commission should establish a Net Lost Revenue Adjustment (NLRA) mechanism to support PP&L's DSM.

- In the past, utility resource acquisition meant primarily supply-side investment, much of it in large units. Demand-side resources involve decentralized decisions and activities on the customer side of the meter. Command and control works less well with many small decisions than with a few large ones.

- In the increasingly competitive electricity industry, utilities seek greater flexibility to respond to customers' needs and interests.

Q. IS THERE ANY EVIDENCE THAT UTILITIES NEED ADDITIONAL MOTIVATION TO PLAN FOR AND IMPLEMENT DSM PROGRAMS?

A. Yes. Many utilities have "concerns" about risks associated with DSM. While a utility could view DSM as an opportunity to become more competitive by improving its array of energy services, it is more common for utilities to view competition (or actually uncertainty about competition) as a reason not to offer comprehensive DSM programs.

One way to get utilities to pursue what they see as a desirable but risky course, is to provide shareholders a reward for excellent performance.

Q. WHAT FEATURES SHOULD THE PP&L INCENTIVE PLAN HAVE?

A. I propose the following criteria by which to evaluate alternative incentive schemes.

1) **The incentives should make the utility's least-cost plan its most profitable plan.** To the extent possible, they should be performance-based, encouraging the utility to maximize the net benefits to PP&L's service territory, or, equivalently, to minimize the total resource cost of providing energy services. They should reward the utility for saving both energy and capacity. There are three elements to the objective of maximizing net benefits:

   (a) The incentive structure should be designed to reward the delivery of energy savings in an efficient manner. The incentives should reward utilities for controlling costs, not for the amount spent on conservation.

   (b) The utility should, ideally, be encouraged to continue to spend money efficiently on conservation programs up to, but not beyond, the point where the costs are equal to the benefits. Over-emphasis on minimizing costs can result in "cream-skimming" or foregoing achievable energy savings.

   (c) The incentives should not reward "gaming", e.g. over-estimating the likely savings of programs.

2) **The impacts of the incentives should be appropriate.**

(a) The incentive available to the company should be large enough to capture the attention of management and stockholders.

(b) Ratepayer impacts should be acceptable.

(c) The system, at this stage, should not be symmetrical. PP&L should be rewarded if it performs exceptionally, but not penalized if it fails to meet a minimum level. Together with the performance-based requirement, this means the Commission should set reasonable demand-side targets for both savings and cost-effectiveness, and establish levels at which rewards take effect.

3) **The mechanisms should be practical.** They should be simple, understandable and easy to administer. It is important that a utility's customers and its officers, managers, and employees understand what the incentives are and how they operate. It does little good to create a complicated incentive system if no one at the Company understands how their actions influence Company earnings. It is also important to be able to explain the system clearly and concisely to the public, state legislators, and other interested parties.

Q. PLEASE DISCUSS THE REASONS TO HAVE REWARDS AND PENALTIES IN THE INCENTIVE SCHEME YOU DESCRIBE ABOVE.

A. A fair incentive scheme would be one which provides symmetrical rewards and penalties. Such a scheme might be based on a reasonable target level of conservation, around which level there would be a "dead band" of plus or minus a fixed percentage. Achievement by the utility of a level of conservation within that band would result in neither rewards nor penalties. If the utility exceeded the upper limit of the band, rewards would be earned, and if it failed to reach the lower end of the band, penalties would be imposed.

<u>Types of Incentive Schemes</u>

Q. WHAT TYPES OF INCENTIVE SCHEMES ARE AVAILABLE?

A. There are a number of different types of incentive schemes. Below I will discuss the leading alternatives -- shared savings and bounty schemes.

Q. PLEASE DESCRIBE THE SHARED SAVING INCENTIVE.

A. **Shared saving** is a common kind of incentive mechanism today. Under this approach the utility keeps a fraction of the net benefit achieved by its DSM programs. Net benefit is the savings in "avoided costs" of energy and capacity less the costs of the DSM program. The fraction kept is typically 10-20 percent, but sometimes as low as 5 percent.

Q. PLEASE DISCUSS THE POSITIVE AND NEGATIVE FEATURES OF SHARED SAVINGS SCHEMES.

A. The unique advantage of shared savings schemes is that they directly reward the utility for the creation of value, by allowing the utility to keep a portion of it. In this manner, they reward any move in the direction of the utility's least-cost plan. The magnitude of the utility's reward is determined by setting the percentage of the net benefits which are retained by the utility, and so both the utility and ratepayers receive shares in the value created.

Q. WHAT DISADVANTAGES DO SHARED SAVINGS SCHEMES HAVE?

A. The difficulty with a shared saving mechanism is the danger of "cream skimming". A utility might target programs with a wide gap between costs and savings, and not pursue programs with lower benefit/cost ratios. To address this problem, New England Electric proposed a two-part shared savings mechanism. In addition to a 10 percent share of net benefits (an Efficiency Incentive), it would also get a 5 percent share of gross benefits or total avoided cost (a Maximizing Incentive). This has been allowed for the Company's Narragansett Electric and Granite State Electric subsidiaries by the Rhode Island and New Hampshire commissions, respectively. In California, San Diego Gas & Electric has a similar scheme. Some utilities are only allowed a share of net benefits over some minimum level.

Q. PLEASE DISCUSS ALTERNATIVE MECHANISMS.

A. A positive incentive can be created by a **bounty** mechanism, which can be an award of a fixed dollar amount for each kW or kWh saved. A variant of a bounty mechanism is a **premium or discount on the authorized rate of return** on common equity. For example, in Colorado Docket No. 91A-480EG the Commission set an incentive/penalty of one basis point for each percentage deviation from the targeted amount, with a dead band of plus/minus 10 percent and a limit of 100 basis points (1 percentage point) more than or less than the authorized return.

Q. ARE THERE OTHER ALTERNATIVES?

A. Yes. A simple alternative is the inclusion of DSM investments in rate base with an allowance of a higher rate of return on those DSM investments than on supply-side investments. For example, there could be a 200-basis-point (2 percentage point) premium on the common equity component of DSM investments.

Q. ARE THERE POSSIBLE DISADVANTAGES TO BONUS OR BOUNTY MECHANISMS?

A. Yes. Bonus and bounty mechanisms that are based on a utility's level of investment in DSM may reward expenditures of money, rather than results. In addition, bonus and bounty mechanisms that are based on savings do not necessarily encourage that the maximum DSM value be pursued. Incentives should not encourage expenditure as such, but the creation of the value with the minimum expenditure. To address the danger that costs might not be adequately controlled, a separate mechanism could be provided for cost control by developing target costs for the packages of conservation programs included in the target DSM savings. However, the addition of this feature makes a bounty scheme more complicated, and still does not address the need to reward savings achievements.

Q. ARE LIMITS SOMETIMES PLACED ON THE AMOUNT OF INCENTIVE EARNINGS A UTILITY CAN RECEIVE?

A. Yes. Some schemes, indeed most, place a cap on the incentive. The most common mechanism is a limit on the additional return on common equity provided by the mechanism over and above the allowed rate of return. The cap is usually in the range of 50 to 100 basis points (0.5 to 1.0 percentage point), applied to the entire common equity of the company. The cap can alternatively be a dollar amount or a limit on the premium earned on the ratebased DSM investment, for example 200 basis points (2 percentage points). Where there is a penalty for under-performance, there may be a limit on the amount of that penalty.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE ALTERNATIVE TYPES OF INCENTIVE MECHANISMS?

A. Most of the incentive mechanisms recently put in place fall into the categories of shared savings or adjustment to return on equity. I generally favor shared savings on the grounds that it provides the utility with the incentives to plan for and implement the appropriate level of DSM. I agree with the California Energy Commission which summarized its position as follows:

> Under the shared savings approach, utilities earn a percentage of the difference between the program costs and the value of the avoided energy supply. Rate of return incentives (which are the other kind available to California utilities) are based on a percentage of dollars spent. Incentives based on a value provide a more effective mechanism than incentives to spend money.

(1992-1993 *California Energy Plan*, pages 40-41.)

Q. DO YOU OPPOSE THE USE OF BOUNTY MECHANISMS?

A. No. I am not averse to the inclusion of some bounty features along with shared savings. But I believe the primary emphasis should be on shared savings.

DSM Incentive Mechanisms Proposed in Pennsylvania

Q. HAVE ANY DSM INCENTIVE MECHANISM BEEN PROPOSED IN THE COMMONWEALTH OF PENNSYLVANIA?

A. Yes, in an Order entered October 7, 1991, the Pennsylvania Public Utility Commission discussed a proposed Energy Efficiency Adjustment (EEA) which contained a performance-based incentive that would allow utilities to retain a portion of the projected net benefits of pre-approved DSM programs. This shared-savings mechanism would apply only to programs which 1) produce viable alternatives to traditional supply options, 2) have a definite resource value which could be readily converted into energy and demand savings, and 3) provide on-peak savings, or a combination of on-peak and off-peak savings.

In 1993, a revised shared-savings DSM incentive mechanism was proposed by the electric utilities as part of an EEA. The revised incentive provided that off-peak demand or energy savings should also be eligible for shared savings incentives because all savings are valuable. In its 1993 DSM Cost Recovery Order, the Public Utility Commission ordered that the proposed EEAs be replaced by a different surcharge mechanism, referred to as the Demand Side Cost Rate (DSCR). The DSCR included a direct cost recovery component for DSM expenditures, as well as a DSM incentive component that was to be based on an (unspecified) off-system sales price multiplied by the number of kWh sales. The utilities would have to verify, in an annual proceeding, the kWh savings of DSM programs.

The Order provided electric utilities with the option to recover the rewards of the DSM incentive either through the surcharge mechanism (the DSCR) or in base rate proceedings.

Q. PLEASE ADDRESS THE EXTENT TO WHICH DSM INCENTIVES CAN BE CALCULATED USING OFF-SYSTEM SALES TO VALUE THE INCENTIVE PAYMENTS, AS PROPOSED BY THE COMMISSION'S APRIL, 1994 ORDER.

A. The average price of off-system sales can serve in an incentive mechanism as a measure of the near-term value of power (i.e., short-run marginal energy costs). Alternatively, bearing in mind the Commission's treatment of this issue, the average of the PJM pool's hourly marginal energy cost for a designated period could be used for a PJM company, like PP&L, and for a non-PJM company to the extent the Commission concluded that the value of power to that company approximated PJM's. In addition, a value for avoided capacity should be added to the PJM marginal energy cost.

Q. WHAT IS THE CURRENT STATUS OF THE DEMAND SIDE COST RATE PROPOSED IN THE 1993 DSM COST RECOVERY ORDER?

A. As I understand it, neither the DSCR, nor any DSM incentives, are currently in place in Pennsylvania as the result of the appeal I cited above. I am proceeding on the assumption that the Commonwealth Court's vacating the PUC's April 7, 1994 Order reversed the calculation for DSM incentives in the form of a surcharge mechanism (i.e. in the DSCR), and that the recovery of DSM incentives can only be lawfully addressed in base rate proceedings.

Q. HAS PP&L ADDRESSED THE ISSUE OF DSM INCENTIVES IN ITS CURRENT BASE RATE FILING?

A. No, it has not.

Q. DO YOU SUPPORT THE PROVISION FOR RECOVERY OF DSM INCENTIVES IN THE FORM OF A SURCHARGE MECHANISM?

A. Yes, I believe that a surcharge provides the most immediate and appropriate recovery mechanism. Postponing the recovery of benefits under a DSM incentive plan ignores the need for an innovative mechanism to encourage utilities like PP&L to pursue additional DSM. I believe the incentive will be more effective if the delay in providing a reward for good DSM performance is minimized. I recommend that the Commission provide PP&L and other electric utilities the option to recover DSM incentives in the form of a surcharge mechanism, to the extent that it is ultimately allowed by the Pennsylvania Supreme Court.

Q. ARE THERE OTHER OPTIONS FOR RECOVERING DSM INCENTIVES?

A. Yes. DSM financial incentives can be recovered through adjustments to base rates. In this case, the amount of the incentive would be based on the amount of DSM savings in the test year. This approach has a significant disadvantage because of the time lag between base rate cases, and because the level of DSM savings may vary significantly from the test year levels. As a result, I recommend that this approach only be adopted if surcharges, or other more timely approaches, are not possible.

Q. HOW SHOULD SAVINGS ESTIMATES BE DETERMINED FOR PURPOSES OF CALCULATING THE DSM INCENTIVE?

A. For purposes of calculating a DSM incentive, and more fundamentally, for calculating whether the programs have positive cost/benefit, it is necessary to measure the savings with reasonable accuracy. Here, I have the following recommendations:

- DSM programs should have a substantial measurement and evaluation component.

- Measured savings data should be used to estimate savings when available.

- If engineering estimates are used initially, measured data should be used to supplement and/or replace this data when such data become available.

4. DSM: RECOVERY OF NET LOST REVENUES

Q. PLEASE DESCRIBE THE ROLE OF NET LOST REVENUE RECOVERY IN MAKING DSM A VIABLE RESOURCE OPTION FOR ELECTRIC UTILITIES.

A. A regulatory barrier exists in many states to utility investment in demand-side management. Under traditional regulation and rate design, utility sales and revenues are linked directly with utility profits, such that a utility's revenues and profits increase whenever it sells an additional kilowatt-hour of energy, or decrease whenever a kWh is conserved through DSM. It is by now widely accepted that utilities are unlikely to undertake aggressive DSM programs unless they are somehow compensated for the lost revenues that result from lower sales. In 1988, the National Association of Regulatory Commissioners urged PUCs to adopt ratemaking policies that would make DSM at least as profitable as supply-side investments. Regulatory commissions in at least 21 states have established various mechanisms to allow utilities to recover lost revenues from DSM.

The preferred approach to lost revenue recovery from DSM programs among utilities and regulators is net lost revenue adjustment (NLRA) mechanisms. NLRA mechanisms allow utilities to recover only the fixed cost portion of lost revenues, and not the variable cost (e.g. fuel costs), since the utility does not incur this cost when sales fall due to DSM -- hence, the recovery of net lost revenues.

Q. PLEASE BRIEFLY DESCRIBE THE DIFFERENT TYPES OF NLRA MECHANISMS SUPPORTED BY COMMISSIONS THROUGHOUT THE U.S..

A. There are three basic types of NLRA mechanisms: a prospective surcharge; a retrospective surcharge; and a deferred account. The surcharge mechanisms are reflected as rate charges on customer bills and typically represent one component of an overall DSM surcharge. A prospective surcharge recovers revenues lost as a result of current year DSM program activities, such that the utility recovers net losses as the losses are incurred. Under this approach, utilities file a forecast of DSM savings and associated net lost revenues for the upcoming program year, and typically submit an annual filing to the commission which, after approval, serves as the basis for an NLRA surcharge. The retrospective surcharge mechanism differs from the prospective surcharge in that it is designed to recover revenues lost from DSM activity in a previous year. Under surcharge mechanisms, net lost revenues due to DSM savings estimates are later reconciled with DSM measurement and evaluation results.

Under the deferred account approach, net lost revenues estimates are tracked through an account, and receive authorization for recovery in the utility's base rate case according to results of DSM measurement and evaluation.

Q. HAVE NLRA MECHANISMS BEEN SUCCESSFULLY IMPLEMENTED BY UTILITIES IN THE STATES?

A. Yes. A number of states have successfully implemented NLRA mechanisms. I have concluded that NLRA is a feasible approach to countering the DSM disincentive. I commend to the Commission a recent study of the Oak Ridge National Laboratory (ORNL), *Assessment of Net Lost Revenue Adjustment Mechanisms for Utility DSM Programs*, January 1995. There are several conditions required for effective NLRA implementation. The most prominent of these conditions are 1) avoiding a strict ex post approach to DSM measurement; 2) involving stakeholders in the process; and 3) setting conditions for lost revenue recovery related directly to DSM program operation and performance.

Q. PLEASE DISCUSS MORE SPECIFICALLY WHY A STRICT EX POST APPROACH TO DSM MEASUREMENT SHOULD BE AVOIDED IF AN EFFECTIVE NLRA MECHANISM IS TO BE IMPLEMENTED.

A. A state's approach to DSM measurement is the most important indication of implementation success of a NLRA. State commissions that do not rely on a strict ex post approach to verify DSM savings are apparently satisfied with their NLRA mechanisms, while state commissions with a strict ex post approach to DSM measurement are apparently less satisfied.

A strict ex post approach attempts to ensure that utilities are compensated only for net lost revenues that can be accurately measured. Net lost revenue recovery is based on after-the-fact measurements of DSM actual impacts that are determined from impact evaluations which focus on the statistical analysis of customer energy use data. The difficulty of this approach lies in the retrospective reconciliation of total program savings, which involves verifying both program participation and unit savings. Unit savings are more difficult and expensive to verify, and increase both the administrative and technical burden of regulatory and utility staff, especially when these savings are tracked over time as required under a deferred account approach.

A less burdensome approach is to limit retrospective reconciliation to program participation, where a utility reconciles projected to observed program participation levels. Because participation levels are generally straightforward to track, they are easy to compare to projected participation. Furthermore, this reconciliation process can be performed shortly after the end of each program year.

Q. DOES THE PENNSYLVANIA COMMISSION REQUIRE UTILITIES TO RECOVER LOST REVENUES USING A STRICT EX POST APPROACH TO DSM MEASUREMENT?

A. As I interpret it for the purpose of my recommendations here, the PUC's 1993 DSM Cost Recovery Order provided that utilities recover net lost revenues caused by DSM through a base rate proceeding using a deferred account to track losses between rate cases, and that DSM savings be measured using a strict ex post approach. The Commission's order also included a provision whereby a utility could petition for special rate relief should it be able to justify inclusion of net lost revenues in its annual DSM balancing account.

The Commonwealth Court later remanded the PUC's order on the issue of net lost revenue recovery. I am not aware of any net lost revenue recovery mechanism in place.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION CONCERNING ITS PREVIOUS RULING THAT REQUIRES UTILITIES TO USE A STRICT EX POST RECONCILIATION METHOD TO DETERMINE NET LOST REVENUES?

A. I recommend that the Commission approve in this case a verification process based on program participation, and not on total energy and demand savings, for the reasons discussed above.

Q. DO YOU SUPPORT THE COMMISSION'S DECISION (ALBEIT A DECISION NOT YET IN EFFECT) THAT REQUIRES UTILITIES TO USE A DEFERRED ACCOUNT APPROACH FOR RECOVERY OF NET LOST REVENUES?

A. My preference is a retrospective surcharge mechanism, included as part of an overall DSM surcharge. Surcharge recovery of net lost revenues comports with the changes in the electric utility industry that have occurred in Pennsylvania since the Commission issued its December 1993 DSM Cost Recovery Order. With utility managements around the country responding to unknown "competitive" changes by cutting staff across the board and DSM programs in particular, it becomes critical that PP&L perceive an immediate opportunity to be made whole for successful DSM.

However, if the Commission holds to its earlier position requiring base rate recovery through a deferred account, then it should allow PP&L to be eligible for "special rate relief", in the form of annual recovery, if PP&L is able to meet certain performance target conditions. An example of a performance target condition would be to base the level of net lost revenue recovery on specific percentages of the stated savings goals in the utility's pre-approved DSM Plan. Indeed, to the extent that the Commission is barred from providing incentives through annual retrospective proceedings, it is even more important to provide utilities with timely and predictable recovery of net lost revenues and, of course, direct costs.

Q. DO YOU RECOMMEND A SPECIFIC ELIGIBILITY CRITERIA BY WHICH PP&L CAN APPLY FOR ANNUAL RECOVERY OF NET LOST REVENUES?

A. Yes. I recommend that the Commission grant PP&L annual recovery of net lost revenues if the Company meets 60 percent of its overall DSM savings goal based on its pre-approved DSM Plan. The utility would have to allege that it had met this goal, offering sworn testimony in its application. That would qualify it for a hearing. Then it would have to prove its allegations in a contested proceeding, with the opportunity for stakeholders to review all relevant information and cross examine. Upon a Commission finding that PP&L had proved it had met the 60 percent floor the annual recovery would be authorized.

Q. HOW ELSE MIGHT PERFORMANCE TARGET CONDITIONS BE USED AS A BASIS FOR RECOVERY OF NET LOST REVENUES?

A. Performance target conditions can also be used as a floor for recovery. A benchmark level should be set requiring that PP&L meet a specific percentage of its overall DSM savings goal in order for it to recover <u>any</u> net lost revenues for that program year. I recommend a level of 60 percent be required by the Commission.

Q. HAS THE COMMISSION RECOMMENDED A METHODOLOGY FOR CALCULATION OF NET LOST REVENUES?

A. No. In its December 1993 DSM Cost Recovery Order, the Commission stated that it did not deem it appropriate or necessary for it to address, with any specificity, the methodologies or procedures for calculating net lost revenues, but that such issues should be resolved during the DSM program evaluation process.

Q. DO YOU RECOMMEND THAT THE COMMISSION RESOLVE THIS ISSUE IN THIS DOCKET?

A. Yes. The Commission should establish a proper methodology for calculation of net lost revenues at this time, even if it opens a generic remand proceeding in which this issue can be addressed.

Q. PLEASE DESCRIBE A METHODOLOGY FOR CALCULATING NET LOST REVENUES.

A. While there are a number of specific methods used to estimate net lost revenues from DSM programs, there is a general procedure common to most methods. Several basic steps are required to calculate net lost revenues.

First, the utility must establish a protocol, to be approved by the Commission, for measuring the annual savings (in kWhs and kWs) for each of the DSM measures. A standard approach is to estimate the energy and demand savings for each measure (the unit savings) and then multiply these per unit savings estimates by the number of participants (or DSM measures) in that program year. In order to perform this first step of the calculation, the utility must have demonstrated the cost-effectiveness, based on the Total Resource Cost Test, of the DSM programs for which it wishes to recover lost revenues.

Second, the utility must estimate the fixed cost component of retail rates. This is typically done by subtracting the short-run variable cost for each rate class from the retail energy rates and demand charges assigned to each rate class.

Third, for each rate class, the fixed cost rate for energy is multiplied by the total annual energy savings, and likewise, the fixed cost for demand is multiplied by the total demand savings. The sum of these products provides a total net lost revenue for each rate class. The sum over all rate classes is an estimate of the utility's total net lost revenues from DSM program activities in that year to be applied either to a surcharge mechanism or added to a deferred account. In Sierra Club Exhibit No. 1C, I provide a formula for how to calculate net lost revenues based on my recommended methodology for reconciling DSM savings.

. . . .

COMMONWEALTH OF PENNSYLVANIA
BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-000943271
	)	
Pennsylvania Power & Light Co. (General rate increase request)	)	

CERTIFICATE OF SERVICE

I hereby certify that I have this, the 16th day of June, 1995, served a true copy of the Sierra Club Brief, upon the following parties of record to this proceeding by First Class Mail, addressed as follows:

ALJ Robert A. Christianson
PA Public Utility Commission
Room G-8A, North Office Building
P.O Box 3265
Harrisburg, PA 17105-3265

Johnnie E. Simms, Esq. (OTS)
Stephen Gorka, Esq.
Kenneth L. Mickens, Esq.
PA Public Utility Comm.
P.O. Box 3265
Harrisburg, PA 17105-3265

Paul Russell, Esq. (PPL)
Associate General Counsel
Pennsylvania Power & Light Co.
Two North Ninth Street
Allentown, PA 18101-1179

David M. Kleppinger, Esq. (ICA)
James P. Dougherty, Esq.
Derrick P. Williamson, Esq.
McNees Wallace & Nurick
P.O. Box 1166
Harrisburg, PA 17108-1166

Tanya J. McCloskey, Esq. (OCA)
Mary C. Kenney, Esq.
Assistant Consumer Advocates
Office of the Consumer Advocate
1425 Strawberry Square
Harrisburg, PA 17120

D. Jane Drennan, Esq.
1216 16th St. NW
Washington, DC 20036

Joan O. Brandeis, Esq. (BET)
Schnader, Harrison Segal & Lewis
Suite 3600
1600 Market Street
Philadelphia, PA 19103-4252

Mr. Maurice Brubaker (BET)
Drazen-Brubaker & Associates, Inc.
P.O. Box 16140
St. Louis, MO 63105-0840

Karen Oill Moury, Esq. (SBA)
Office of Small Business Advocate
Suite 1102 - Commerce Building
300 North Second Street
Harrisburg, PA 17101

David A. McCormick, Esq. (DOD)
Regulatory Law Office
Office of the Judge Advocate General
Dept. of the Army
901 North Stuart Street - Room 713
Arlington, VA 22203-1837

Mr. Robert D. Knecht
Industrial Economics Incorporated
2067 Massachusetts Ave.
Cambridge, MA 02140

Thomas P. Gadsden, Esq. (PPL)
Anthony C. DeCusatis, Esq.
David B. MacGregor, Esq.
Morgan Lewis & Bockius
2000 One Logan Square
Philadelphia, PA 19103

James P. Melia, Esq. (UCC)
Kirkpatrick & Lockhart
240 North Third Street
Harrisburg, PA 17101-1507

Mr. Craig R. Kuennen (CEO)

Energy Services Manager
Commission on Economic Opportunity
211 South Main Street
Wilkes Barre, PA 18701-1596

Stephen J. Selden, Esq. (BET)
Assistant General Counsel
Bethlehem Steel Corporation
1170 Eighth Avenue
Bethlehem, PA 18016-7699

Robert P. Haynes, III, Esq. (FOD)
Mette, Evans & Woodside
3401 North Front Street
P.O. Box 5950
Harrisburg, PA 17110

Eric Epstein
TMI Alert
2308 Brandywine Drive
Harrisburg, PA 17110

Mary Lou Morin

Mary Lou Morin, Secretary to
Alan J. Barak (Sup. Ct. 67886)
Attorney for Sierra Club
Mid-Atlantic Energy Project
Widener University Energy Law Clinic
3700 Vartan Way
Harrisburg, PA 17110-9450
V/717-541-1967
F/717-541-1970

\ppl1\scbrief.cos

COMMONWEALTH OF PENNSYLVANIA
BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-000943271
Pennsylvania Power & Light Co. (General rate increase request)	)	

SIERRA CLUB'S BRIEF

CERTIFICATE OF SERVICE

Alan J. Barak,
Attorney for Sierra Club

Alan J. Barak
Mid-Atlantic Energy Project
Widener Energy Law Clinic
3700 Vartan Way
Harrisburg PA 17110

Daniel W. Rosenblum, Director,
Mid-Atlantic Energy Project
Of Counsel

717/541-1967 (voice)
717/541-1970 (fax)

Dated: June 16, 1995

McNEES, WALLACE & NURICK

ATTORNEYS AT LAW

100 PINE STREET
P. O. BOX 1166
HARRISBURG, PA 17108-1166
TELEPHONE (717) 232-8000
FAX (717) 237-5300

June 16, 1995

John G. Alford, Secretary
Pennsylvania Public Utility Commission
B-20, North Office Building
P.O. Box 3265
Harrisburg, PA 171230

VIA HAND DELIVERY

In re: Pennsylvania Public Utility Commission, et al., v. Pennsylvania Power & Light Company; Docket No. R-0943271

Dear Secretary Alford:

Enclosed please find the original and nine (9) copies of the Main Brief on Behalf of the PP&L Industrial Customer Alliance. All parties of record have been duly served as evidenced by the attached Certificate of Service.

Please date stamp the enclosed copy of this transmittal letter and kindly return for our filing purposes.

Very truly yours,

McNEES, WALLACE & NURICK

By [signature]
Derrick P. Williamson

DOCUMENT FOLDER

RECEIVED
'95 JUN 16 PM 2:00
PA. P.U.C.
INFO. CONTROL DIV.

DPW/mts
Enclosures

cc: Certificate of Service

ORIGINAL

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION, ET AL.,	:	
v.	:	DOCKET NO. R-00943271
PENNSYLVANIA POWER & LIGHT COMPANY	:	

MAIN BRIEF ON BEHALF OF THE PP&L INDUSTRIAL CUSTOMER ALLIANCE

Air Products and Chemicals, Inc.
Alumax Mill Products, Inc.
Appleton Papers, Inc.
Armstrong World Industries
BOC Gases
CertainTeed Corporation
Chamberlain Manufacturing Corporation
Cressona Aluminum Company
ESSROC Materials, Inc.
Grinnell Corporation
Hercules Cement Company
Hershey Foods Corporation
International Paper Company
Lafarge Whitehall Cement
Liquid Carbonic Industries
Magee Carpet Company
M&M/Mars, Inc.
Praxair, Inc.
R. R. Donnelley & Sons
The Stroh Brewery Company
Thomson Cons. Electronics, Inc.
Victaulic Co. of America

David M. Kleppinger
Derrick P. Williamson
McNEES, WALLACE & NURICK
100 Pine Street
P. O. Box 1166
Harrisburg, PA 17108-1166
(717) 237-5214

Counsel for PP&L Industrial
Customer Alliance

Dated: June 16, 1995

TABLE OF CONTENTS

Page

<u>**TABLE OF CITATIONS**</u>

<u>Page</u>

<u>**CASES**</u>:

<u>**ADMINISTRATIVE DECISIONS**</u>:

TABLE OF CITATIONS (continued)

Page

I. INTRODUCTION

On December 30, 1994, Pennsylvania Power & Light Company ("PP&L" or "Company") filed Supplement No. 50 to Tariff Electric- Pa. P.U.C. No. 200, proposing a \$261 million, or 11.7%, increase in its annual base rate revenues, effective February 28, 1995.[1]

On January 18, 1995, the Lehigh Valley Power Committee filed a Formal Complaint against PP&L's proposed rate increase and tariff changes. On January 30, 1995, the PP&L Industrial Customer Alliance filed an Amended Complaint noting the change in the name of the industrial intervenor group from Lehigh Valley Power Committee to PP&L Industrial Customer Alliance ("PPLICA").

PPLICA is an ad hoc association of 22 energy-intensive industrial customers receiving firm and interruptible service under PP&L's existing Rate Schedule LP-5 and other tariffs and riders; most PPLICA member companies have historically purchased substantial quantities of electricity from PP&L pursuant to its optional interruptible service tariffs. PPLICA members consume in excess of 2.4 billion kWh of electricity on the PP&L system at a cost of over \$105 million. PPLICA members are engaged in competitive regional, national and global markets. PPLICA members employ over 26,000 people in PP&L's service area, purchase over \$230 million in goods and services from the local economy, and

---

[1]The Company mistakenly publicized a \$261 million increase when, in reality, the Company has actually requested an increase of \$240 million; as noted by PPLICA witness Baron, the Company's mistaken \$261 million increase must be reduced by \$21.790 million because PP&L erroneously incorporated the effects of a JCP&L capacity cost recovery and offsetting ECR credit in its \$261 million request. See PPLICA Statement No. 7, pp. 12-14.

pay upwards of $64 million per year in state and local taxes. PPLICA Statement No. 7, pp. 5-6.

Other parties filing Complaints or Petitions to Intervene in this proceeding are the Office of Consumer Advocate ("OCA"), the Office of Small Business Advocate ("OSBA"), the U.S. Department of Defense and the Federal Executive Agencies ("DOD"), Bethlehem Steel Corporation ("BethSteel"), Mid-Atlantic Energy Project ("Sierra Club"), The Lancaster Chamber of Commerce and Industry, the University/College Coalition ("UCC"), Crown American Realty Trust, the Central Eastern Pennsylvania Fuel Oil Dealers ("CEPFOD"), the Commission on Economic Opportunity ("CEO"), and Eric Epstein ("Epstein"). The Office of Trial Staff ("OTS") also participated actively in the proceeding. Additionally, numerous consumers filed complaints and letters or placed telephone calls to the Commission protesting the rate increase.

By Order entered January 27, 1995, the Commission instituted an investigation into PP&L's proposed rate increase and suspended Supplement No. 50 for a period not longer than seven (7) months from February 28, 1995, or until September 28, 1995, pursuant to Section 1308(d) of the Public Utility Code, 66 Pa.C.S. § 1308(d). The case was assigned to Administrative Law Judge ("ALJ") Michael C. Schnierle for hearings and Recommended Decision. On March 7, 1995, Judge Schnierle convened a prehearing conference. On March 15, 1995, the presiding officer was changed from ALJ Schnierle to ALJ Robert A. Christianson.

ALJ Christianson convened extensive hearings as well as numerous public input meetings. Hearings were held in Harrisburg on March 21, 23, 24, 27-29, 1995, during which PP&L's direct case was introduced into evidence and its witnesses were cross-examined. Further hearings were held on April 25-28 and May 2-3, 1995, for the purpose of cross-examining witnesses testifying on behalf of the various intervenors. On May 23-26, 1995, hearings were held for the purpose of presenting rebuttal, surrebuttal, and oral rejoinder testimony and cross-examination thereon. Hearings concluded on May 26, 1995, with the close of the evidentiary record.

II. PREAMBLE

The 22 members of PPLICA are among PP&L's largest customers, and their competitive vitality is undoubtedly critical to the health of the local and state economies. As relatively sophisticated consumers of electricity, PPLICA members are keenly aware of the rapid advances being made throughout the country towards competitively priced electricity and customer choice of electric supplier. With each passing week, even a casual observer of electric utility industry trade material will quickly note developments by numerous states investigating electric power competition, transmission access, and competitively priced electricity. Not only are state commissions pursuing these concepts, but several individual investor-owned utilities are actively promoting a more competitive electric purchasing environment. These significant movements were underway when PP&L filed this base rate case in December of 1994 and have increased almost exponentially since then.

Against this national backdrop of increased customer choice and competitively priced electricity, PPLICA members were literally stunned by the timing and secrecy of PP&L's $261 million (actually $240 million), 11.7% system average increase on December 30, 1994. PPLICA members were (and still are) baffled by PP&L's desire to seek such a significant base rate increase at a time when most other investor-owned electric utilities are seeking to cut costs and to stabilize or lower rates in order to meet the challenges of competition. Upon examination of PP&L's base rate filing, PPLICA members became even more confused by PP&L's behavior and apparent motivations. A cursory review of a few major revenue requirement issues reveals a blatant attempt by PP&L to "cash in" on as many revenue requirement issues as possible prior to true competition developing in the electric utility industry. Among the significant misguided revenue requirement claims attempted by PP&L are:

(1) a 13.0% return on common equity when the Commission most recently awarded an 11.5% return on common equity to West Penn Power Company;

(2) a $45 million revenue requirement claim for prospective fossil fuel dismantling costs when the Commission had recently rejected an identical claim from West Penn Power Company;

(3) a $19 million revenue requirement claim for accelerated depreciation on fossil fuel fired plants based on a depreciation schedule which fails to match PP&L's committed retirement dates for those plants;

(4) a modification to PP&L's own sinking fund depreciation methodology for the *Susquehanna Steam Electric Station which accelerates $30 million in* depreciation expense in direct contradiction to the rationale proffered by PP&L's when it proposed its original depreciation method in the original Susquehanna proceedings;

(5) an attempt to build in a $35.5 million per year base rate increase through an energy cost rate modification in order to accommodate the possible return of 945 MW of capacity previously sold to Jersey Central Power & Light Company.

These revenue requirement claims by PP&L are novel at best, particularly in light of Commission precedent; at worst, these proposals represent a disingenuous attempt to inflate the revenue requirement. PPLICA, as well as the other parties to this case which have addressed revenue requirement issues in detail, immediately saw through the transparent attempt by PP&L to unduly benefit its shareholders at the expense of its customers prior to the advent of competition. The Commission should not, and cannot, condone such activity when many other state commissions and many other investor-owned utilities are moving in the opposite direction - they are seeking ways to reduce costs and rates in preparation for competition.

Unfortunately, as PPLICA members more closely analyzed the PP&L filing, the Company's corporate policy became even more painfully clear. Less than three years ago, PP&L voluntarily filed an Optional Interruptible Power provision to Rate Schedule LP-5. All PPLICA members are served at their largest facilities in PP&L's service territory on Rate Schedule LP-5. At the time PP&L submitted the Optional Interruptible Power provision of Rate Schedule LP-5 in 1992, only four of the 22 PPLICA members were taking interruptible service. The competitive attractiveness of the Optional Interruptible Power filing by PP&L convinced numerous other PPLICA members to accept the lower quality and riskiness of interruptible service in exchange for a more competitively priced electricity rate. While no PPLICA member realistically anticipated that the level of the Optional Interruptible Power rate would remain constant if and when PP&L filed a base rate case, no PPLICA member taking Optional Interruptible Power service could have dreamed that PP&L would ask the Commission, in less than three years, to essentially eliminate the competitive electric rate advantage provided by PP&L's Optional Interruptible Power service.

To the utter shock of PPLICA members, PP&L has proposed to do just that. In a case where the Company is seeking an 11.7% system average increase, it seeks to increase the Optional Interruptible Power provision of Rate Schedule LP-5 by over 27%. Individual PPLICA members may see increases as high as 36%. As an indication of how determined PP&L apparently is to punish the LP-5 interruptible group of customers, it has proposed a significant rate design change for interruptible service which produces a 22% increase even if the Commission awards no increase to PP&L. As the Commission approaches this case, it cannot lose sight of this unprecedented result and the impact of that result on the competitiveness of PPLICA members. As state government officials and this Commission reference their respective desires to be concerned with economic development and a positive business climate, each will quickly recognize that the PP&L rate filing is the antithesis of a positive business climate seeking to promote economic retention and development.

The remainder of this Brief by PPLICA will address the PP&L rate case on a traditional basis. However, when the Commission ultimately decides this case, it must do so, not only in the context of a traditional rate base/rate of return analysis, but also with the knowledge of what is occurring outside of Pennsylvania's borders. That world is one where many commissions and investor-owned utilities have already recognized that a competitive electric world is upon us and that customers with choices will actively pursue those choices unless the local investor-owned utility and state commission is responsive to their respective needs. Through PPLICA's participation in this case, the Commission can reach no other conclusion than that PP&L has failed miserably at measuring its customers' needs. PPLICA hopes that the Commission will recognize the error of PP&L's philosophy and place this utility back on a course which recognizes the realities of the electric utility marketplace.

III. SUMMARY OF ARGUMENT

Proper reliance upon the Discounted Cash Flow method in determining PP&L's return on equity indicates that an appropriate rate of return on common equity for PP&L is 10.85%. In addition to the application of this rate of return on equity, various revenue requirement proposals offered by PP&L must be rejected or modified by the PUC. Specifically, the Company's claims associated with prospective fossil fuel plant dismantling, shorter fossil fuel plant depreciation lives, the levelization of SSES depreciation, increases to the annul accrual for SSES, implementation of the voluntary Early Retirement Program, and SFAS 106 amortization must be rejected or modified. In addition, it must be clarified that PP&L has actually requested an increase of only $240 million, not $261 million because it has included certain ECR related adjustments. Based upon PP&L's actual requested increase of $240 million, these PPLICA-recommended adjustments result in PP&L being entitled to a base rate increase of no more than $24 million.

For the purpose of allocating any allowed revenue increase, the Company's 12 CP cost of service study methodology, as modified by PPLICA, should be utilized. Toward that end, PPLICA's proposed distribution should be adopted as it pursues the goal of achieving a 50% reduction in existing subsidies, and it effects a systemwide movement of class rates of return toward cost of service while respecting the need for gradualism in ratemaking.

PP&L's proposed revenue allocation and rate design proposal must be rejected. In particular, PP&L's brazen proposal to increase interruptible rates by upwards of 35% (and by 22% even if there is no rate increase) is ill-founded, anti-competitive and violative of all notions of gradualism. PP&L's allocation to and design of the interruptible rate must also be rejected. The PPLICA alternative, maintenance of the current interruptible rate design, should be approved.

ARGUMENT

IV. REVENUE REQUIREMENT

A. The Commission Should Grant PP&L A Rate Of Return On Common Equity At The PPLICA Recommended Level Of 10.85%.

1. A 10.85% Rate of Return on Common Equity Represents a Reasonable Return for PP&L in Today's Capital Markets.

PP&L should be allowed a rate of return on common equity of 10.85%. This return on equity is commensurate with returns for electric utilities with below average risk, such as that enjoyed by PP&L. PPLICA Statement No. 8, p. 3.

PP&L sells electricity to approximately 1.2 million customers in central and eastern Pennsylvania. PP&L also makes sales of electricity to other utilities and PJM Interchange Power sales. Despite $1.4 billion in construction expenditures for the period 1991 through 1993, PP&L's 1993 average return on equity was 13.1%. Moreover, for the five year period from 1989 through 1993, the Company's return on equity averaged 13.6%. Id. at 10. Consequently, in terms of its bond ratings, PP&L is rated A2 by Moody's and A- by Standard & Poor's ("S&P"). Moody's stated in its September 1994 report on PP&L that the near term rating outlook for the company is stable, and Value Line's Investment Survey dated March 17, 1995, assigned the Company's common stock a Safety Rank of 2; this rank indicates that a stock is considered to be safer and less risky than most common stocks. Id.

at pp. 11-12. In short, PP&L has been identified as an electric utility with below average risk.[2]

In determining a fair rate of return on common equity, it is axiomatic that the estimated cost of equity must be comparable to the returns of other firms with similar risk structures and should be sufficient for the firm to attract capital. See Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591, 64 S.Ct. 281 (1944); Bluefield W.W. & Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679, 42 S.Ct. 675 (1923). The rate of return should be consistent with the return being offered by risk-comparable firms.

PPLICA witness Baudino employed a Discounted Cash Flow ("DCF") analysis of PP&L and two comparison groups of companies that are similar to PP&L to identify the proper rate of return on common equity for PP&L.

Performing a DCF analysis on PP&L is the best way to directly estimate the cost of equity for the Company and that price data can be directly obtained for PP&L regarding its stock and estimates of investor-expected growth. PPLICA Statement No. 8, pp. 19-20.

---

[2]PPLICA remains baffled, to say the least, by PP&L's proposal to increase rates to its interruptible customers by 27% to nearly 35% (increasing interruptible rates by more than three times proposed system average increase of 11.70%). The excessive increase proposed by the Company for interruptible customers could increase the risk that those customers self-generate or bypass the Company; hence, the Company has voluntarily increased its overall business risk as a result of its proposed rate increase to the interruptible customers. PPLICA Statement No. 8, pp. 12-13; Tr. at 62 (cross-examination of PP&L witness Moul). Query how the PUC can "reward" PP&L with a 13.0% return on common equity when PP&L's misguided interruptible rate proposal has increased its business risk.

Witness Baudino also used a comparison group of utilities with risk structures similar to PP&L's in order to add an additional level of confidence and robustness to his DCF analysis. In addition, witness Baudino performed a DCF analysis of PP&L witness Moul's similar "barometer" group. Reliance upon the DCF method is, of course, in keeping with recent Commission precedent. See Pennsylvania Public Utility Commission, et al., v. City of Bethlehem (Water), 160 PUR4th 375, 414 (1995).

a. A properly performed DCF analysis produces a return on equity range of 10.53% to 11.57% for PP&L, with 11.05% being an appropriate midpoint.

Under the DCF method, the return on common equity is essentially determined by adding expected dividend yield to expected growth rate. PPLICA Witness Baudino utilized a six-month period from September 1994 through February 1995 to identify an average dividend yield for PP&L of 8.39%. PPLICA Statement No. 8, p. 23.

In order to estimate the expected dividend yield for PP&L, the current dividend yield must be moved forward and timed to account for dividend increases over the next twelve (12) months; PPLICA Witness Baudino, consistent with past Commission practice, estimated the expected dividend yield by multiplying the current dividend yield by one plus one-half the expected growth rate. This results in an expected dividend yield for PP&L ranging from 8.48% to 8.52%. Id. at 23-30.

The expected growth rate is a function of earnings growth and the pay-out ratio. Witness Baudino relied upon Value Line and the Institutional Brokers' Estimate Service

("IBES") to estimate the expected growth rate for PP&L. Id. at 24. Witness Baudino also reviewed historical growth.[3]

Witness Baudino identified forecasted growth for PP&L ranging from 1.00% to 2.05%. He identified historical growth rates for five and ten years of 3.42% and 2.75%, respectively. Id. at 28. He, therefore, recommends a growth rate range for PP&L of between 2.05% and 3.05%, with the low end of the rate based on Value Lines forecasted retention growth, and the upper end of the range close to the average of the five- and ten-year historical growth rates. Id. As aforementioned, Witness Baudino excluded most of the forecasted growth rates from consideration because he believes that they reflect lower near-term growth prospects for PP&L and don't reflect the longer term prospects for the Company's growth. Id. In short, a range of 2.05% to 3.05% represents a reasonable balance between near-term and long-term growth prospects for the Company. Id. at 29.

Based upon his estimates of expected dividend yield for PP&L (8.48% to 8.52%) and the expected growth rate for PP&L (2.05% to 3.05%), witness Baudino identified a DCF cost of equity for PP&L ranging from 10.53% to 11.57%, with 11.05% being the midpoint for the range. Id. at 29-30, Table 1.

---

[3]Witness Baudino typically does not use historical growth rates in his DCF analysis; however, because some of the analysts' forecasts of near-term growth for PP&L and the two comparison groups that Witness Baudino utilizes are quite low, he supplemented his analysis with historical growth rates to develop a better estimate of long-term expected growth for PP&L. Id. at 25-26.

b. A properly performed DCF analysis produces a return on equity range of 10.05% to 10.88% for the PP&L comparison group, with 10.47% being an appropriate midpoint.

Witness Baudino also provided a DCF analysis of a comparison group of similarly situated utilities. He chose this comparison group by utilizing two initial screens based on Value Line safety rank and bond ratings. He identified the following group: Atlantic Energy, Inc., Carolina Power & Light Company, Delmarva Power & Light Company, Dominion Resources, Inc., Kansas City Power & Light Company, New England Electric System, Oklahoma Gas & Electric Company, and St. Joseph Light & Power Company. Id. at 22-23.

Utilizing a DCF approach similar to that used to analyze PP&L, he estimated an average dividend yield for the comparison group of 7.35%. Id. at 30. As in his PP&L analysis, Witness Baudino then adjusted the current average dividend yield for the group by one plus one-half the expected growth rate to obtain the expected dividend yield for the group ranging from 7.45% to 7.48% Id. at 32.

Witness Baudino also identified a forecasted growth rate for the comparison group ranging from 1.45% to 2.80%. Five and ten-year historical growth rate averages ranged from 3.02% to 3.38%. Id. at 31. Based on this data, Witness Baudino recommends a growth rate range for the comparison group of 2.60% to 3.40%. The bottom of the range is based on the average of forecasted growth rates less the value line dividend growth rate and represents a reasonable lower end for investor expectations even though the dividend growth suggests that it could be even lower. The upper end of the range is supported by the ten-year historical growth rates. Id.

Based upon these expected dividend yield and expected growth rate ranges, Witness Baudino identified a DCF return for the comparison group ranging from 10.05% to 10.88%, with 10.47% being the midpoint. Id. at 32.

c. A properly performed DCF analysis produces a return on equity range of 10.26% to 10.98% for PP&L witness Moul's barometer group, with 10.62% being an appropriate midpoint.

PPLICA Witness Baudino also performed a DCF analysis of the barometer group used by PP&L witness Moul. He identified an average dividend yield for the barometer group of 7.66%. Id. at 33. He obtained an expected dividend yield for the barometer group of 7.76% to 7.78%. Again, using forecasted and historical growth rates, witness Baudino identified (for the barometer group) an expected growth rate ranging from 2.50% to 3.20%. Adding the expected dividend yields to the expected growth rates, Witness Baudino identified a DCF return for PP&L Witness Moul's barometer group of 10.26% to 10.98%, with a midpoint of 10.62%. Id. at 34-35, Table 3.

d. The Commission should grant a rate of return on common equity to PP&L of 10.85%, resulting in a weighted cost of capital for PP&L of 9.22%.

Having applied the DCF model to PP&L, a comparison group and PP&L witness Moul's barometer group, PPLICA witness Baudino has identified, and recommends, a rate of return on equity for PP&L of 10.85%. As the table below illustrates, this recommendation is the approximate average of the PP&L and Moul barometer group analyses, and it is near the upper end of the range for the Baudino comparison group:

	DCF Range	Midpoint
PP&L	10.53% - 11.57%	11.05%
Barometer Group	10.26% - 10.98%	10.62%
Comparison Group	10.05% - 10.88%	10.47%

The 10.85% rate of return on common equity for PP&L reflects investor expectations and strikes an appropriate balance between risk and reward in today's marketplace. Id. at 36.

2. The Company's Proposed Rate of Return on Common Equity of 13.00% is Based Upon Faulty Analyses and Must be Rejected.

Through the direct testimony of PP&L witness Moul, PP&L has proposed a recommended rate of return on equity of 13.00%. The Company has requested an opportunity to earn an overall fair rate of return of 10.22%. PP&L Statement No. 12, pp. 1, 54-55. PP&L argues that it should be allowed this overall rate of return "so that it can complete in the capital markets and be adequately compensated for its changing business risk." Id. at 57. PP&L Witness Moul's proposal is derived from his four measures of the cost of equity: the Comparable Earnings Approach, the DCF model, the Risk Premium Analysis, and the Capital Asset Pricing Model ("CAPM"). Id. at 3. Using these models, witness Moul measured the cost of equity for PP&L as well as a barometer group of eight electric companies comparable in risk to PP&L. Id. PP&L's analysis is grossly flawed, and its return on equity proposal must be rejected.

a. PP&L witness Moul's DCF analysis overstates recommended growth rate, is not supported by the data presented in his testimony, and improperly includes an "adder" for "market-wide factors."

In his DCF analysis, PP&L witness Moul recommended a 3.5% growth rate for PP&L and his barometer group. In addition, he added another 0.5% for what he termed "market-wide factors" to arrive at a recommended growth rate for PP&L of 4.0%. Given his estimates of 8.49% and 7.97% (hereunder) for expected dividend yield, these estimated growth rates resulted in witness Moul identifying a recommended DCF range for PP&L and the barometer group of 12.49% and 11.97%, respectively. PP&L Statement No. 12, pp. 44-45.

Witness Moul's selection of an expected growth rate of 3.5% is unsupported by his direct testimony. Indeed, witness Moul explained that he followed an approach to estimating growth that is not rigidly formatted, but he never explained how he arrived at 3.5% growth rate for PP&L and the comparison group. In short, Witness Moul failed to identify the technique(s) that he actually utilized in arriving at his recommended growth rate. PPLICA Statement No. 8, p. 41. This analysis must therefore be discounted.

As noted by PPLICA witness Baudino, a 3.5% growth rate for PP&L is only supported by a five-year historical growth rate analysis. The vast majority of other growth rates, historical and forecasted, are significantly below 3.5%. As such, a growth rate of

3.5% substantially overstates growth for PP&L given the available evidence. Id. In addition, historical and forecasted growth rates for the barometer group indicate an estimated growth rate ranging from 2.5% to 3.2%, not 3.5%. Id. at 35, 41.

Finally, Witness Moul's proposal to add 0.5% to his improperly estimated growth rate in recognition of "market-wide factors" must also be rejected as witness Moul has failed to offer any analysis or evidence supporting this proposed adjustment. It is wholly inappropriate to assume that investors would elevate their growth expectations for PP&L and the barometer group without any significant substantiation for such an addition. See Id. at 42.

As a consequence of these errors in his analysis, witness Moul's proposed estimated growth rate for PP&L and the barometer group of 4.0% must be rejected by the Commission. Given that witness Moul's recommendation (that PP&L and the barometer group are entitled to respective rates of return of 12.49 and 11.97%) is based upon this inflated and unsubstantiated expected growth rate, his DCF proposal is suspect at best. See also OTS Statement No. 1, pp. 39-40.

b. PP&L witness Moul's Comparable Earnings approach must be rejected as it is an accounting-based, rather than market-based approach.

PP&L Witness Moul has relied in part on a Comparable Earnings approach in identifying his proposed rate of return on common equity for PP&L. This approach requires the analysis of returns experienced by firms that are non-regulated. Various (allegedly pertinent) categories of comparability were established in order to identify firms that are allegedly comparable to PP&L.

Witness Moul's analysis of firms other than public utilities under his Comparable Earnings approach identified an average of the historical and forecasted rates of return for these companies of 13.50%. PP&L Statement No. 12, p. 38. As an alleged check on his comparable earnings figure, PP&L witness Moul stated that he computed a DCF cost of equity for each of the twenty-three (23) non-regulated firms comprising his comparable earning group which resulted in an average rate of return on equity for these companies of 15.4%. Id.

Witness Moul's Comparable Earnings approach greatly overstates investors' required return for PP&L. PPLICA Statement No. 8, p. 42. In addition to the inherent inconsistency of using a comparison group which excludes regulated utility companies, witness Moul utilized accounting returns on book value for the companies in his sample. As such, the Comparable Earnings method is not a market-based approach to estimating the cost of equity for PP&L, and it assumes, contrary to economic theory and actual experience, that investors' required returns are based on historical accounting returns on book equity for firms in unregulated industries. Id. at 43. Investor required returns are based on the market price of their investment, not on accounting returns on book value. Id. Indeed, the Comparable Earnings approach may be completely unaffected by changes in the market cost of capital. As such, reliance on the accounting based comparable earnings approach is clearly misplaced.

In addition, PP&L witness Moul's assertion that the DCF analysis that he performed on his group of comparable companies verifies the reasonableness of his 13.50% return for the comparable earnings group is absurd. His DCF result for the group of companies of 15.4% is nearly 200 basis points greater than his recommended return based on comparable earnings. This clearly does not confirm his comparable earnings analysis, and any assertion that his DCF analysis provides an appropriate check on his comparable earnings result must be rejected. The Commission should reject the Comparable Earnings method utilized by PP&L Witness Moul.

c. PP&L witness Moul's use of the risk premium analysis must be rejected as it is based on a series of historical earned returns that are of no relevance and because witness Moul arbitrarily adjusted his risk premium results downward.

Having identified a 9.0% yield on A rated public utility bonds as a reasonable expectation for PP&L, witness Moul then identified a risk premium of 4.75%, resulting in a proposed rate of return on common equity for PP&L of 13.75% based on his risk premium analysis. PP&L Statement No. 12, p. 48.

As the Commission noted in PP&L's last base rate case, Pennsylvania Public Utility Commission v. Pennsylvania Power & Light Company, 59 PaPUC 332 (1985), it is extremely difficult to determine a reasonable equity cost rate under the risk premium methodology. See id. at 394 (indeed, the Commission adopted a common equity cost rate for PP&L in its last base rate case based upon the DCF calculation). Most recently, the Commission reaffirmed its practice of relying upon the DCF method to the exclusion of the historical-based risk premium and CAPM approaches. See Pennsylvania Public Utility

Commission, et al., v. City of Bethlehem (Water), 160 PUR4th 375, 414 (1995). This is, of course, consistent with past Commission declarations:

> . . . [W]e [i.e., the Commission] cannot accept that historic experienced earnings reflect the cost of capital. We know of no reputable analyst who would seriously argue that experienced earnings represent the cost of capital, except by pure happenstance. But, such is the inherent assumption of each methodology [Risk Premium and CAPM].
>
> * * *
>
> Accordingly, we conclude that we can place little credence in the results of these methodologies.

Pennsylvania Public Utility Commission, et al., v. Pennsylvania Power Company, 67 PaPUC 91, 164 (1988).

Despite the Commission's well-founded aversion to reliance upon the risk premium (and CAPM) method, PP&L has engaged in a risk premium analysis which incorporates the types of factors which have caused the PUC to reject the approach in the past. Witness Moul developed a series of historical earned returns from the Standard & Poor's Utility Index, and he also calculated the return series for long-term corporate and public utility bonds. The historical returns he utilized cover the period from 1928 to 1993. Witness Moul then derived a number of risk premiums for different time periods for application in his analysis. The appropriate cost of capital is by definition forward looking; thus the use of historical earned returns is an unsuitable measure of investors' expected risk premiums. Indeed, risk premiums have not been constant over time. As such, to assume that investors require a risk premium that is based on some arbitrarily chosen period in the past is risky, and as recognized by the Commission, subject to a great deal of divergence in application. See PPLICA Statement No. 8, pp. 45-46. In short, there is no substantiation for the assumption that investors expect current equity returns to be based on risk premiums derived from historical earned returns. Thus, the Commission should, consistent with past practice, reject the risk premium analysis utilized by PP&L witness Moul. Id. at 46-47.

d. PP&L witness Moul's CAPM analysis must be rejected, consistent with PUC precedent, as it is flawed.

PP&L Witness Moul also utilized the Capital Asset Pricing Model ("CAPM") in ascertaining his recommended rate of return on common equity, though witness Moul admits that the CAPM analysis contains a variety of assumptions and must be checked by other methods for consistency. PP&L Statement No. 12, p. 48.

Witness Moul performed two variations of the CAPM analysis. Under the first variation, a traditional CAPM analysis, he identified a CAPM return in the range of 13.34% to 13.50%. Utilizing his second variation, the "zero-beta" CAPM analysis, Moul identified a CAPM return in the range of 14.54% to 14.62%. PP&L Statement No. 12, pp. 51, 53.

The CAPM approach relies heavily on the use of betas in identifying an appropriate rate of return. PPLICA Statement No. 8, p. 48. Unfortunately, as noted by PPLICA Witness Baudino, there is strong evidence that the beta is not the primary factor in determining the risk of a security (even Witness Moul admits as such; PP&L Statement No. 12, Appendix E, p. E-3). In addition, considerable amount of judgment must be employed in determining the risk-free and market return portions of the CAPM equation. PPLICA

Statement No. 8, p. 49. As such, the range of results provided by the CAPM analysis may vary widely.

In addition to this problem, PP&L Witness Moul again utilized historic returns in estimating the market return portion of the CAPM. Such historical data should not be used to measure current investor return requirements and expectations. PPLICA Statement No. No. 8, pp. 49-50. Moreover, Witness Moul ignored data from Value Line which indicated a lower expected market return than that utilized by witness Moul in his analysis. Witness Moul also failed to include other pertinent forecasted data from IBES on the Standard & Poor's 500 Composite. Id. at 50. As such, Witness Moul's narrow analysis significantly overstates the market return. PPLICA Witness Baudino provides a number of examples of other market data that Witness Moul failed to consider. See PPLICA Statement No. 8, pp. 50-51. As such, it is clear that witness Moul's forecasted market return is grossly overstated. Id. at 52.

Though PPLICA does not advocate the use of the CAPM approach in identifying a rate of return on common equity for PP&L (as this is not consistent with past Commission practice and because reliance on the CAPM is surely misguided), PPLICA witness Baudino computed an alternative CAPM return on equity based upon his realistic estimates of market return. That analysis identified a CAPM return on equity utilizing PP&L's beta ranging from 10.47% (based on five-year bonds) to 11.86% (thirty-year bond), and a CAPM return on equity using Moul's barometer group beta ranging from 10.67% (five-year bond) to 12.10% (thirty-year bond). PPLICA Statement No. 8, pp. 52-54.

PP&L Witness Moul's CAPM analysis severely overstates the return on equity. A CAPM analysis utilizing more realistic estimates of market return indicates a return substantially lower than that advocated by witness Moul and return that is consistent with the range of DCF results presented by witness Baudino in his direct testimony. As such, the Commission should reject PP&L witness Moul's CAPM results as they are clearly unreasonable and excessive. Such rejection is in keeping with the PUC's practice of ignoring CAPM (and risk premium) results. See, e.g., Pennsylvania Public Utility Commission, et al., v. Pennsylvania Power Company, 67 PaPUC 91, 164 (1988) (rejecting risk premium and CAPM methods).

e. PP&L witness Moul's analysis implicitly incorporates an inflated level of risk due to the Company's proposed increase to interruptible customers.

Finally, PP&L's cost of capital, as proposed by PP&L Witness Moul, is arguably a product of PP&L voluntarily increasing its own risk through its proposal to substantially increase rates to its interruptible customers. PP&L is proposing to increase interruptible rates by 27% to 35%, and by 22% (due to rate design changes) even of the Company is granted no increase! See PP&L Statement No. 8, pp. 12-15 (and Exhibit OGK-3); Tr. at 2202-03. Despite voluntarily increasing that risk, and thereby overstating its cost of capital, PP&L has obstinately refused to modify its absurd interruptible rate design and increase.

PP&L has recognized, however, that sales to its industrial interruptible customers create business risk for PP&L these industrial customers are more influenced by the level of business activity and are susceptible to self-generation and/or bypass. PP&L Statement No.

12, p. 14. As PP&L also recognizes, its success in serving these twenty-nine (29) largest industrial customers (who represent about 7.5% of PP&L's revenue) is subject to the price of alternative energy sources and broadening competition in the supply of electricity. Id. at 15. PP&L also recognizes that increasing a customer's rates also increases the risk that an industrial customer might self-generate or seek other competitive alternatives. Tr. at 62-63. For this reason, the Company states through the testimony of witness Moul: "It is imperative that the Company maintain competitive pricing in the face of increasing competition and expansion of open access in the transmission network. For PP&L, competitive pricing and maintenance of its market share represent key challenges for the future." Id.

The reality of the marketplace mandates these statements (and consonant actions), but PP&L has exposed itself as a utility unwilling to accede to the realities of competition. Rather than provide interruptible customers with competitive pricing, PP&L has proposed a 27% to 34% increase to its interruptible customers. Indeed, PP&L witness Kasper has offered that interruptible rates should increase by 22% even if PP&L is allowed no increase in revenues. Tr. at 2202-03. As such, given the fact that PP&L has recognized the competitive riskiness of serving these industrial customers, PP&L's proposal represents a voluntary increase in business risk. PP&L has thereby implicitly increased its cost of capital claim.

PPLICA, of course, is adamant that PP&L's proposal to increase its interruptible rates in the face of the recognized competition that the Company faces must be rejected. See Sections V.C and V.D., infra. Toward that end, PP&L's proposed cost of common equity must be deflated to recognize the reduction in risk that will occur with the rejection of PP&L's misguided proposal to increase interruptible rates.

f. The Various Errors in PP&L's Rate of Return Analyses Mandate that the PUC Reject PP&L's 13.00% Proposed Rate of Return on Common Equity.

All of the analyses (comparable earnings, DCF, CAPM, Risk Premium) undertaken by PP&L in support of its proposed rate of return on common equity are flawed to varying degrees. Consequently, the Commission must reject the PP&L proposal for a 13.0% return on equity. Accord OTS Statement No. 1, pp. 39-44; OCA Statement No. 1, pp. 6-7.

The Commission need only look at the consistency of all the other rate of return witnesses to recognize the fallaciousness of the PP&L proposal. The OTS recommends a return on equity of 10.63%. OTS Statement No. 1, p. 10. The OCA has proposed a rate of return on common equity of 11.10%. OCA Statement No. 1, p. 6. PPLICA, of course, has sponsored a return on equity for PP&L of 10.85% (which, incidentally, is the approximate midpoint of the respective OTS and OCA proposals).[4] These proposals range from 10.63% to 11.10%; not one approaches the obviously inflated 13% figure sponsored by PP&L. PP&L's proposal must be rejected.

[4]Even DOD has indicated support for a return on common equity of no more than 11.50%. DOD Statement No. 1, pp. 13-14.

3. PP&L's Revenue Requirement Must be Reduced by $5 Million to Reflect the Company's Actual September 30, 1994, Capital Structure Instead of the Company's Proposed Capital Structure for the 1995 Future Test Period.

In identifying a rate of return on common equity for the Company, PP&L witness Moul utilized the Company's proposed capital structure for the 1995 future test period. Tr. at 52. That structure incorporates the effects of an equity issuance of $100 million that the Company may pursue in August, 1995, and the effect of this additional equity is to boost the Company's common equity ratio by almost a full percentage point over the actual September 30, 1994, capital structure. Tr. at 52-53. All other things being held constant, this increase in the common equity ratio results in an additional revenue requirement of about $5 million per year for the Company. PPLICA Statement No. 8, pp. 37-38; PPLICA Statement No. 9, p. 32.

As PP&L witness Moul admitted under cross-examination, the Company is not committed to this August equity issuance. Moreover, PP&L did not conduct a numerical study evaluating whether such an increase would be a prudent financing effort. Tr. at 53-55. Consequently, it is inappropriate for the Company to utilize capital structure in identifying its rate of return on common equity that is based on conjecture and speculation. As the Commission noted in Pennsylvania Public Utility Commission, et al., v. National Fuel Gas Distribution Corp., et al., 73 PaPUC 552, 605-06 (1990), where a company seeking a base rate increase proposes the inclusion of a possible issuance of two million shares of common equity, thereby increasing the Company's common equity ratio, that capital structure will be denied as being too speculative. That precedent must apply with equal force in this proceeding.

As such, PPLICA Witness Baudino utilized the 1994 capital structure in identifying the Company's rate of return on common equity. To the extent that PP&L Witness Moul's analysis and proposal with respect to PP&L's proposed rate of return on common equity is based upon a proposed capital structure which incorporates the effects of a $100 million common equity issuance in August, 1995, PP&L's rate of return on common equity and requested revenue increase must be adjusted downward by $5.017 million (see PPLICA Statement No. 9, p. 32), and the capital structure proposed by witness Baudino (and quantified by witness Kollen at PPLICA Statement No. 9, Exh. LK-4) should be adopted.

4. Conclusion

This Commission has routinely relied upon DCF analyses in identifying the appropriate rate of return on common equity for utilities in base rate proceedings. Indeed, in Pennsylvania Public Utility Commission v. Philadelphia Suburban Water Company, 75 PaPUC 391 (1991), the PUC expressly rejected both the risk premium and CAPM methods and relied primarily upon the DCF method in determining the appropriate cost of common equity. Id. at 430; see also Pennsylvania Public Utility Commission, et al., v. Pennsylvania Power Company, 67 PaPUC 91 (1988). In PP&L's most recent base rate proceeding, the Commission expressly noted that the risk premium analysis is subject to wide divergence of result, and consequently relied on the DCF methodology. 59 PaPUC at 394. Recently, in Pennsylvania Public Utility Commission, et al., v. West Penn Power Company, Docket No. R-00942986, Commission Order entered December 29, 1994, the Commission approved a rate of return on common equity for West Penn based exclusively on DCF analysis. Id. at 94-100. Most recently, the PUC utilized the DCF method and expressly excluded the risk premium method in determining the cost of equity. Pennsylvania Public Utility Commission, et al., v. City of Bethlehem (Water), 160 PUR4th 375, 403-14 (1995).

In keeping with Commission precedent regarding the use of the DCF model, PPLICA witness Baudino has provided that the rate of return on common equity for PP&L should be set at 10.85%.

Though PP&L utilized DCF analyses (in part), PP&L's proposal for a rate of return on common equity of 13.00% must be rejected. That proposal is based upon a variety of analyses to include the Comparable Earnings Approach, the Risk Premium Approach, the CAPM Approach, and certain DCF analyses. As aforementioned, the Commission has routinely frowned upon the use of the risk premium and CAPM methods, and has shown a decided reliance upon the DCF method. In any event, the various analyses under taken by PP&L witness Moul, to include his DCF analyses, are flawed for a variety of other reasons and must be rejected. In addition, the Moul analysis implicitly incorporates a higher risk as a result of the Company's efforts to substantially increase rates for interruptible customers.

Finally, the capital structure proposed by PP&L is based upon a potential equity issuance of $100 million that has tentatively been scheduled for August 1995. Given the speculative and hypothetical nature of this capital structure, it must be rejected, and the capital structure utilized by PPLICA witnesses Baudino and Kollen should be implemented for the purposes of this proceeding.

The Commission should approve a rate of return on common equity for PP&L consistent with the analysis of PPLICA witness Baudino in the amount of 10.85% (resulting in a weighted cost of capital for PP&L of 9.22%). This rate of return on common equity represents a reasonable rate of return in today's marketplace, and it is comparable to the rates of return proposed by the OTS and OCA.

B. PP&L'S Inflated Request for a $240 Million Increase Should be Reduced by No Less Than $216 Million.

PPLICA has recommended that PP&L be allowed a return on common equity of 10.85%. This reduces the Company's requested revenue requirement ($261.635 million) by approximately $85 million. In addition, PPLICA Witness Baudino's recommendation to utilize the September 30, 1994, actual capital structure (rather than the Company's use of a proposed capital structure which considers a projected $100 million equity issuance to which the Company is unwilling to currently commit) further reduces the Company's requested revenue requirement by approximately $5 million.

Consistent with PPLICA Witness Baron's identification of an error in the Company's computation of its deficiency, the Company's requested $261 million increase should first be reduced by $21.790 million (to $239.845 million) to correct for PP&L's inclusion of its JCP&L capacity proposal and its offsetting ECR credit. PPLICA also recommends that various other revenue requirement adjustments (as outlined, infra.) be effected to result in an additional reduction to PP&L's proposed increase of approximately $126 million.

In summary, PP&L's requested $240 million increase (as adjusted regarding the ECR issues), must be reduced from $240 million to no more than $24 million, consistent with PPLICA's recommended 10.85% return on common equity, the use of a historic capital structure, and the other revenue requirement adjustments identified by PPLICA Witnesses Kollen and Baron discussed infra.

1. PP&L's Proposal to Include, as an Expense Item Within the ECR, the Revenue Requirements Associated with Returned JCP&L Capacity Must be Rejected.

PP&L has proposed that the calculation of its ECR be modified to permit recovery of the non-energy revenue requirements of each returning 189 MW increment of the 945 MW slice that it has been selling to Jersey Central Power & Light ("JCP&L"), that 945 MW slice being reduced by 189 MW per year until the agreement terminates at the end of the year 2000. PP&L Statement No. 7, p. 22. In short, the Company wants automatic increases to its retail customers to offset reduced future revenues associated with its sale of capacity of JCP&L. PPLICA Statement No. 7, p. 11. Under the Company proposal, it would include $35.5 million in its revenue requirement amount as per its January 1, 1996, ECR calculation and continuing with a $35.5 million rate increase each year for a total of five years. PPLICA Statement No. 7, p. 73. The credit that the Company would include if its JCP&L proposal is accepted would be approximately $20.8 million for the test year (but likely to decrease going forward). Id. at 74.

The Company's proposal to include, as an expense item within the ECR, revenue requirements associated with returned JCP&L capacity must be rejected as the proposal is wholly unreasonable. PP&L is requesting that the Commission grant automatic rate increases today of $35.5 million per year for each of the next five years as a result of PP&L's lost wholesale transaction. Id. at 75. The proposal would amount to requiring that the Commission approve, prospectively, single issue rate increases without consideration given to any offsetting expenses, revenues, or other factors which may negate the necessity for such increases in the future. Moreover, the revenue requirement associated with the generating capacity being sold currently (and in PP&L's test year to JCP&L) is not at issue in this base rate proceeding; these revenue requirements have been properly allocated to PP&L's wholesale jurisdiction. PP&L should not be provided the opportunity to automatically increase retail rates whenever a wholesale power contract is terminated. PP&L's unprecedented request should be summarily rejected by the Commission. Id. at 75.

Even if the Company's proposal is rejected, the Company has numerous options to deal with the revenues lost as a result of losing the sale of capacity to JCP&L. First, PP&L can identify other utilities or entities to which it could sell such capacity, and second, PP&L could file a retail rate case in Pennsylvania if it believes it is not earning a fair rate of return on its prudent, used and useful investment. Id. at 76. Toward this end, PP&L should be entitled to retain any capacity-related revenues which it receives as a result of selling all or part of the 945 MW of JCP&L "returned" capacity to other parties.

In short, the Company proposed a $261 million increase in base rates (capturing the effect of its JCP&L proposal) and an offsetting ECR credit of approximately $21 million. Should the Company's JCP&L proposal be adopted, the Company would receive a base rate increase (based on its entire revenue requirement proposal of) of $261 million offset by an ECR credit for off-system capacity revenues of approximately $21 million, resulting in a net increase to ratepayers of $240 million. Should the Company's JCP&L proposal be rejected (as it should be), the Company will withdraw its proposal to credit the ECR for off-system capacity revenues, but credit base rates, again resulting in a net increase to base rates of $240 million. Tr. at 653, 657, 2147-48; see PPLICA Statement No. 7, pp. 11-15, 73-77.

PP&L also proposes that if its JCP&L proposal is accepted, the Company will credit its ECR with 100% of capacity related off-system revenues received from PJM installed capacity credit, output reservation and transmission entitlement sales. PP&L Statement No. 7, p. 23. In so doing, the Company transfers the risk associated with these sales to the retail customers; PPLICA believes that these revenues should be retained in base rates so that the risk of future sales decreases or increases rests with the Company. PPLICA Statement No. 7, p. 11. The credit is a base rate offset to revenue requirements in this proceeding and should be treated as such; even PP&L witness Kleha agrees that it is a base rate item. See Tr. at 2148-50. Regardless of the Commission's ultimate disposition of the Company's JCP&L request, the Commission must include the fixed, test year level of these revenue credits within base rates and remove them from the ECR. PP&L Statement No. 7, p. 77.

2. PP&L's Request to Prematurely Recover Projected Fossil Fuel Plant Dismantling Costs Must be Rejected as a Matter of Law.

The Company inflated its revenue requirement by attempting to prospectively recover costs of dismantling fossil fuel units. In this rate proceeding, this proposal amounts to an increase in the Company's depreciation expense by adding prospective negative net salvage value. PP&L Statement No. 13, p. 2. The Company's proposal must be summarily rejected.

Negative salvage has been defined as "the loss a utility suffers upon the retirement of property resulting from the necessity to expend funds in excess of the salvage value in order to remove the property." Penn Sheraton Hotel v. Pennsylvania Public Utility Commission, 198 Pa.Super 618, 623, 184 A.2d 324, 327 (1962). As a matter of law, a utility cannot recover prospective negative net salvage (i.e., a cost, not yet incurred, but estimated to occur at some time in the future) via annual or accrued depreciation. Id. at 327-29. In short, a utility cannot presently recover future expenses associated with the dismantling of fossil-fuel units by including such amounts in the rate base.

However, an exception to this rule does exist with regard to nuclear plants. This Commission has allowed advance recovery of decommissioning costs for both the radioactive and non-radioactive portions of a nuclear plant, where legitimate concerns regarding safety and liability indicate that removal of the non-radioactive portion of the plant is proper. Pennsylvania Public Utility Commission v. Pennsylvania Power Company, 67 PaPUC 91, 140 (1988); Pennsylvania Public Utility Commission v. Philadelphia Electric Company, 74 PaPUC 1, 161 (1990).

The Commission's allowance for a decommissioning expense relates to non-radioactive portions of nuclear plants, not the decommissioning of independent fossil fuel plants. See Pennsylvania Public Utility Commission v. Duquesne Light Company, 66 PaPUC 518, 679 (1988). Furthermore, the Commission has expressly rejected the argument that no distinction should be drawn between prospective negative net salvage as it applies to nuclear plants and non-nuclear plants. Pennsylvania Public Utility Commission v. West Penn Power Company, 54 PaPUC 602, 629-30 (1981). In so doing, the Commission emphasized the uncertainty of when, if ever, fossil plant decommissioning will occur, and the fact that nuclear plant decommissioning involves vital health and safety issues. Id.

This Commission has steadfastly refused to allow an annual expense adjustment for prospective negative net salvage associated with the retirement of independent non-radioactive (i.e., fossil fuel) generating plants for ratemaking purposes. Most recently, West Penn Power Company filed for a base rate increase wherein it sought prospective recovery for costs associated with dismantling its coal-fired generating stations. Pennsylvania Public Utility Commission v. West Penn Power Company, Docket No. R-00942986 at 63 (December 29, 1994). In keeping with precedent, the Commission rejected West Penn's claim:

> Consequently, we reject the Company's claim because of its uncertain and speculative nature and because this claim is patently counter to existing precedent.

Id.; See also, Pennsylvania Public Utility Commission v. West Penn Power Company, 54 PaPUC at 629-30.

Similarly, PP&L bases its cost projections on speculation and assumptions. Future costs of dismantling remain unknown, unmeasurable, and inherently lacking in objectivity. In addition, PP&L has not accounted for possible unit upgrade requirements, life extensions and changes in technology. To further emphasize the uncertainty of such projections, PPLICA witness Kollen points out that over the last 45 years the actual total salvage proceeds received by PP&L exceeded the actual decommissioning costs. PPLICA Statement No. 8, p. 9. Under current law, PP&L cannot presently recover for prospective negative net salvage.

Not only has PP&L failed to provide any rationale in support of its request, but also, as presented above, there is simply no legal basis at either the federal, state or Commission level entitling the Pennsylvania Power and Light Company ("PP&L") to establish a decommissioning fund for its fossil fuel units. Id. at 8.

In addition to the legal prohibition, no regulatory or accounting mandates exist requiring recognition of fossil fuel plant dismantling costs that may materialize in the future. Id. Indeed, PP&L's only attempt at identifying such a source is a reference to the National Building Code ("NBC"). The NBC, however, only allows the recovery of prospective negative net salvage when the fossil fuel plant has been deemed "unsafe." PP&L's witness, Thomas LaGuardia, admitted that all of PP&L's 16 fossil fuel plants currently merit a "safe" standing. Tr. at 998. Therefore, even under the NBC, PP&L's request must be denied. Furthermore, even if the plants became "unsafe", compliance with the NBC (returning the plant to "safe" status) may be satisfied by means other than dismantling or plant removal. Tr. at 999.

Moreover, the Company's request lacks any legitimate economic rationale and would result in clear inequity. Unlike contributions to nuclear decommissioning trust funds, contributions made to fossil fuel decommissioning trust funds are not tax deductible. Further, contrary to the assumptions made by the Company, a fossil fuel decommissioning trust fund would earn less in after taxes than a nuclear decommissioning trust fund. PPLICA Statement No. 8, p. 10. Finally, PPLICA witness Kollen points out the wide difference between the Company's before tax return sought by the Company on its investment (15.78%) and the before tax return offered by the Company to ratepayers for their investment (6.88%). Id.

Given that the Company's proposal is economically unwise and inequitable, beyond lacking any legal or regulatory basis, this proposal must be denied, and its revenue requirement claim must be reduced by $45.022 million (expenses would be reduced by

$43.041 million), consistent with the recommendations of the OTS and the OCA regarding this revenue requirement issue. Id. at 4; see also OTS Statement No. 2, p. 1; OCA Statement No. 4, pp. 17-23.

3. PP&L's Request for an Additional $19 Million Based on the Approval of Shorter Depreciation Lives for Certain Fossil Fuel Plants Must be Rejected.

PP&L has proposed to shorten the lives for depreciation accounting purposes of the fossil fuel generating units at Holtwood, Martins Creek, and Sunbury. PP&L Statement No. 4, p. 6. The Company's proposal to shorten the depreciable lives for these certain fossil fuel plants increases PP&L's revenue requirement by approximately $19 million (and its depreciation expense by $16.687 million). PP&L Statement No. 4-R, p. 18.

PP&L's proposal to shorten the depreciation lives of these plants must be rejected as PP&L has indicated that it has not expressly committed to the early retirement of these plants and because PP&L has failed to provide evidence that adequately supports its proposal.

PP&L witness Krall has stated that the factors necessitating PP&L's proposal for the shorter depreciation lives merely indicate that "the continued operation of these units beyond [the originally projected] time frame [is] less certain than it is was thought to be in 1988 when the current deactivation dates were established." PP&L Statement No. 5-R, p. 3. PP&L has indicated no intent to commit to retire these plants. OTS Cross-examination Exhibit No. 2 (which references a portion of PP&L's Resource Planning Report dated May, 1994) indicates that PP&L has no plan to retire any steam electric system during the next twenty (20) years (i.e., before the year 2014), in direct contravention to PP&L's proposal to shorten the depreciable lives of certain fossil fuel plants in this proceeding. See Tr. at 110. Moreover, although PP&L Witness Krall admits that the depreciation schedule is based on a 2003 deactivation date, he also has admitted that the company's Five Year Coal Upgrade Plan filed with the Commission on May 2, 1994, confirms the Company's intent to continue to invest in the Sunbury, Martins Creek and Holtwood units through the year 2013; he has noted that the Company does not have a definitive plan of actually retiring these units prior to 2013. See Tr. at 110, 188-89. As such, the record is clear that PP&L has no current commitment to deactivate consistent with its proposal to shorten the depreciation lives for the pertinent fossil fuel plants. As a matter of logic, and ratepayer equity, PP&L's proposal to shorten those depreciation lives for the Sunbury, Martin's Creek, and Holtwood units must be therefore rejected.

This is especially so given that the Commission typically requires that any proposal to decrease the useful life of a plant for the purpose of depreciation must be supported by sufficient evidence. Indeed, in Pennsylvania Public Utility Commission v. West Penn Power Company, 54 PaPUC 602 (1981), West Penn proposed to decrease the useful life of a plant from 40 to 33 years. The Commission rejected the proposal on the basis that it was not supported by sufficient evidence. Id. at 613-15.

In this proceeding, given that it is clear that PP&L has no current intent to actually retire those plants prior to the year 2013, the PP&L proposal must be rejected. As further noted by PPLICA witness Kollen, the Company has not provided any economic basis or quantified data or analyses that shortening the depreciable lives for these units is either necessary or appropriate. PPLICA Statement No. 9, p. 13. The Company's Five-Year

Upgrade Plan for coal fired generation indicates that the continued operation of the Holtwood, Martins Creek and Sunbury units is both prudent and economical through at least the year 2013. Id. at 14-15. In conjunction with the Company's absolute failure to commit to the early retirement of these plants, the record militates unequivocally toward rejection of the PP&L proposal. The Company's revenue requirement proposal should be reduced by 19.222 million. Id. at 4. Again, the OTS, OCA and PPLICA are in agreement on this revenue issue. OTS Statement No. 2, p. 1; OCA Statement No. 5, p. 7-11.

4. PP&L's Request for an Additional $30 Million in Revenue Resulting from its Proposal to "Levelize" the Modified Sinking Fund Depreciation for SSES Must be Rejected.

The Company has included in its revenue requirement $30.626 million resulting from its proposal to change its modified sinking fund depreciation for SSES to a "levelized" depreciation method. In short, the Company has proposed a revision that will result in a levelized amount of annual depreciation, through 1998, to replace the modified sinking fund ("MSF") method which was previously approved by the Commission. See PP&L Statement No. 4, pp. 7-8. The Company is proposing to include in customers' rates a levelized amount of depreciation in place of the annual increasing amount via the MSF. This levelized amount would remain in effect until January 1, 1999, at which time the depreciation expense amount would decrease to the straight-line level. Id. at 12-13.

The PP&L proposal must be rejected for a number of reasons. First, the request constitutes an attempt to reach beyond the end of the test year to examine a projected cost increase without accounting for potentially offsetting cost reductions or revenue increases.

PPLICA Statement No. 9, p. 17. Second, PP&L's request to accelerate depreciation recovery does not include an offsetting carrying charge benefit in order to levelize the effect of the increase on ratepayers; thus ratepayers are unreasonably harmed. Third, any assertion by the Company that a rejection of its proposal will cause the Company to over- recover when its SSES depreciation expense is reduced to straight-line levels commencing in January 1999 is speculative and fails to recognize various options that the Commission will have to offset the over recovery. Id. at 18.

Finally, in Pennsylvania Public Utility Commission v. Pennsylvania Power & Light Company, 59 PaPUC 332 (1985), the Commission approved the modified sinking fund method (which PP&L now proposes to change) ostensibly because that depreciation methodology was intended to match the economic benefits of the plant over its life cycle to the ratepayers. Id. at 352-353. Indeed, as recognized by PP&L Witness Hoch, use of the modified sinking fund treatment was an attempt to maintain rate stability by not increasing rates beyond what might be expected to be a fairly reasonable level, though witness Hoch recognizes that the PP&L proposal to end MSF in this proceeding would increase the revenue requirement. Tr. at 117. As such, the Company should not be entitled to modify its MSF treatment of the SSES, thereby increasing the revenue requirement for ratepayers in contravention to the express rationale for allowing the MSF treatment in the first instance. The Company's revenue requirement proposal should therefore be reduced by $19.927 million. PPLICA Statement No. 9, p. 5. The OTS and the OCA agree that PP&L's proposal must be rejected. OTS Statement No. 2, p. 1; OCA Statement No. 5, p. 3-6.

5. <u>PP&L's Request to Increase its Allowed Annual Nuclear Decommissioning Accrual for SSES Must be Rejected.</u>

The Company's revenue requirement proposal includes a request to increase the allowed annual decommissioning accrual for the Susquehanna units by more than four times the previous level, resulting in an increase to revenue requirement of nearly $20 million. Toward this end, PP&L witness LaGuardia estimates that the total cost of decommissioning the Susquehanna units is $804.259 million in 1993 dollars. PP&L Statement No. 13, p. 3. This total cost includes both nuclear and non-nuclear decommissioning costs, PP&L staff and internal costs, and it incorporates various other assumptions to include that contingency factors should be applied. Perhaps, most importantly, the Company has annuitized the total projected decommissioning costs based upon an assumed after tax rate of return of only 5.50%. PPLICA Statement No. 9, pp. 19-20. The Company's proposal must be rejected.

The Company's assumption of a 5.50% rate of return on ratepayer funds is well below the return that the Company claims is required for its own rate base investments. The Company should be required to perform at a comparable level. PPLICA Statement No. 9, pp. 22. If the Company is not required to manage its trust fund investments at a level comparable to that which it manages its rate base investments, the Company will have no direct incentive to manage the trust fund aggressively on behalf of the ratepayers. The Commission should require that the decommissioning accrual be computed utilizing PP&L's allowed overall rate of return, recognizing that the Commission should use the allowed overall rate of return for PP&L as an earnings performance standard for its trust fund investments. PPLICA Statement No. 9, p. 23. If the Commission were to allow PP&L's

requested rate of return of 10.23%, then the annual SSES nuclear decommissioning accrual must be reduced by $18.911 million to account for the Company's need to achieve a comparable rate of return on its trust fund. Id. at 5, 25; see PPLICA Exh. LK-4 (to compute rate of return).

6. PP&L's Request to Recover the Costs of its Voluntary Early Retirement Program Must be Reduced by the Amount of Savings the Company Would have Otherwise Retained Through the End of the Test Year.

The Company has requested recovery of approximately $76 million amortized over a five year period for the cost of its Voluntary Early Retirement Program ("VERP"). The Company's cost of service for this item is $15.172 million per year. See PPLICA Statement No. 9, p. 26.

The Company's proposal must be adjusted in two specific ways. First, the Company did not reduce the total cost of its VERP program by the amount of the savings which it will have obtained by the end of the test year and by the date that rates for this proceeding are implemented; consequently, if the Commission does allow the recovery of PP&L's VERP costs, the total costs should first be reduced by the amount of the savings the Company would otherwise retain. Id. at 27. Otherwise, the Company would be allowed to recover the gross cost of the VERP despite the fact that it was also the direct beneficiary of nine months of VERP related savings from the implementation of its plan beginning December 31, 1994, through September 30, 1995 (the anticipated conclusion of this case). The Company's allowed recovery of VERP costs must be based on its net cost, not the gross costs. Id. In utilizing the net cost of the VERP, the Company's revenue requirement is reduced by approximately $5 million.

A second problem with the Company's proposed VERP cost recovery plan is that the Company's proposal to amortize over five (5) years is inappropriate and unreasonable. The Company has proposed that it will pay the residual of the VERP costs in the form of pension supplements and social security bridge payments for eleven (11) years, from 1995 through 2005. However, the Company's proposal to recover those costs over a five year amortization period would enable the Company to obtain full recovery well in advance of the payment of the items. As such, the Company should be required to amortize over a ten (10) year straight-line amortization period for its net VERP costs. This is much more equitable than a five year period since it more closely parallels the length of time during which actual payment will be made under the VERP. Id. at 28-29. The effect of extending the amortization period from five to ten years reduces the Company's revenue requirement by an additional $4 million. Id. at 29. Accounting for both adjustments, the Company's revenue requirement proposal should be reduced by $9.564 million. Id. at 5.

7. PP&L's Request to Recover an Amortization of Prior Period SFAS 106 Deferral Amounts Must be Rejected Given that the Legality of Such Recovery is Currently Pending Before the Courts of this Commonwealth.

The Company has requested a revenue requirement of $1.894 million to recover over 17 years the incremental SFAS No. 106 costs it incurred from January 1, 1993, through September 30, 1995 (the expense effect is $1.797 million) . The Commission authorized deferral of these amounts, but that Order was subsequently reversed by the Commonwealth

Court. The Commission should not now grant recovery of a cost disallowed by the Commonwealth Court as the legality of such recovery is currently pending before the Supreme Court. The Commission is legally precluded from approving the Company's proposal, thus, the Company's requested increase should be reduced by $1.894 million. PPLICA Statement No. 9, p. 5.

8. Summary of PPLICA Recommended Adjustments.

Having recognized that PP&L is in fact requesting an increase of $240 million, the following revenue requirement adjustments must be incorporated to reflect the appropriate maximum revenue increase that PP&L should be allowed:

- Reject current recovery of future fossil plant dismantling costs ($45.022 million).
- Reject cost for shorter depreciation lives ($19,.222 million).
- Reject levelization of SSES MSF depreciation ($30.626 million).
- Modify nuclear annuity accruals ($19.927 million).
- Reduce VERP costs ($9.564 million).
- Reject SFAS 106 deferral ($1.894 million).
- Utilize actual capital structure ($5.017 million).
- Utilize 10.85% return on equity ($84.687 million).

In total, these adjustments to the revenue requirement represent a reduction of approximately $216 million, thus, utilizing PP&L's actual requested revenue requirement increase of $240 million, PP&L should be allowed a revenue increase of no more than $24 million. See PPLICA Statement No. 9, pp. 4-6.[5]

[5]PPLICA has provided the Tables required by the Commission at Appendix "F." The data contained in those tables is slightly different from the revenue requirement adjustments (above) because it incorporates tax and other related effects. The bottom line is that the total revenue adjustment number ($24 million) is the same (both on Table 1 and above) with respect to PPLICA's recommended revenue increase allowance.

V. RATE STRUCTURE AND RATE DESIGN

A. PP&L's 12 Coincident Peak Cost Of Service Study Methodology Should Be Utilized, As Modified By PPLICA, For The Purpose Of Revenue Increase Allocation.

1. PP&L's 12 Coincident Peak Methodology, As Modified by PPLICA, Represents a Reasonable Cost of Service Study That Should be Adopted by the Commission.

The Company has proposed to use a 12 coincident peak ("CP") allocation methodology in this proceeding. As noted by PP&L Witness Kleha, the Commission accepted the Company's 12 CP allocation methodology in its last base rate case, and the Company has continued to utilize this methodology in various Federal Energy Regulatory Commission proceedings. Tr. at 552.

Although PPLICA believes that a single coincident peak methodology, based on the winter peak of PP&L during the test year, would be the ideal basis for allocating costs to the customer classes, given the Company's prior use of the 12 CP method and the Commission's adoption of that method in the last PP&L base rate case, PPLICA is proposing that the Commission accept and utilize a PPLICA-modified 12 CP methodology. PPLICA Statement No. 7, p. 19.

PPLICA does not agree with the Company's twelve CP cost-of-service study as filed. Three specific adjustments must be engineered to accurately reflect the proper rate of return produced by each customer class at present rates. Id. at 22-23. Indeed, the relative rate of return indices based on the Company's filed 12 CP cost of service study at present rates indicate (erroneously) that Schedule LP-5 and Schedule ISA are earning below the system average rate of return, while all other classes, save the residential class, are earning above the system average rate of return. See id. at 20.

a. The Company's proposed treatment of interruptible load within its filed cost-of-service study must be adjusted.

In reflecting the presence of interruptible load on Rate Schedules LP-4, LP-5 and ISA, the Company applied a $300/kW credit to electric plant in-service for each kW of interruptible load on these rate schedules, at a total credit of approximately $86 million. PP&L then allocated this $86 million cost over Rate Schedules LP-4, LP-5 and ISA as a cost of service. Id. at 23-24. In short, the Company engaged in a two step process to allocate its costs in providing interruptible service: interruptible customers were first allocated production costs on the same basis as firm customers, then the interruptible customer class cost responsibility was reduced by allocating a rate base credit (based on the cost of a combustion peaking unit). Tr. at 554.

PPLICA strongly disagrees with the Company's specific treatment of its interruptible load within the cost-of-service study; however, even if one were to accept the Company's framework, the Company's recognition of interruptible load in retail cost-of-service analysis is not correct.

The Company's cost of service analysis utilizes actual revenues produced by both firm and interruptible customers under Rate Schedule LP-5 (as well as LP-4 and ISA). As such, these revenues include a substantial amount from interruptible customers, thus the Company's study reflects a current interruptible credit substantially in excess of the revenue requirement effected by PP&L's flawed $300 per kW credit methodology. The use of this approach contributes to Rate Schedule LP-5 earning a return below the system average rate of return during the test year under the Company's 12 CP analysis. PPLICA Statement No. 7 p. 25.

In short, the Company's methodology in this proceeding assumes that the interruptible credit is a plant-in-service credit of $300 per kW; i.e., a revenue requirement of approximately $3.00/kW month. However, the actual interruptible credit being proposed by the Company in this proceeding is $6.00 per kW for two hour interruptible load and $8 per kW for thirty (30) minute notice interruptible load. Id. at 26. The result of this mismatch is to penalize customer classes that contain interruptible load by requiring these classes to pay the difference between the $3/kW assumed by the Company in its cost of service study and the actual credits being proposed for these customers of $6.00 and $8.00 per kW. This is an inappropriate treatment for cost-of-service purposes and does not reflect a reasonable methodology for measuring the contribution made by each class to the overall system revenue requirements. Id. at 27.

Consequently, the Company's cost of service study must be adjusted to reflect the proper treatment of interruptible load which requires that the Company's proposed interruptible credits of $6.00 and $8.00 per kW be utilized as the basis for measuring the value of interruptible load for cost-of-service analysis purposes.[6] The Company's study should include a revenue credit for each customer class containing interruptible load (LP-4,

---

[6]PPLICA emphasizes that use of the $6.00 and $8.00/kW interruptible credit is only appropriate for cost of service study analytical purposes. As discussed infra., the existing rate design for interruptible service on Schedule LP-5 should be retained as is.

LP-5, and ISA) that is equal to the revenue credits actually being proposed by PP&L as embodied in its rate proposals. The cost of paying these revenue credits would then be allocated to all customer classes on the basis of the 12 CP production demand allocation factor. This adjustment will correct the mismatch contained in the Company's analysis. Id.

In addition, the Company's analysis is also suspect to the extent that its cost of service study witness has utilized a 287 MW of interruptible load for his cost of service study while PP&L witness Sipics identified a 345 MW capacity equivalent demand for the same interruptible demand. Tr. at 618-17. Thus, for the purpose of the cost of service study, the value of interruptible load as a capacity credit has been undervalued in any event.

b. PP&L's 12 CP Study Must be Modified to Reclassify and Allocate NUG Purchased Power Expenses.

PP&L has included approximately $220 million of NUG purchased power expenses in its retail cost-of-service analysis. The Company has allocated this purchased power expense on a 100% energy basis. Tr. at 624; PP&L Exhibit JMK-2. However, in recovering NUG expenses within the ECR, a portion of those expenses are assigned on a demand basis and a portion on an energy basis. PP&L Exhibit Future 1, Schedule D-3, tr. at 625. As such, PP&L has failed to provide a consistent allocation of these expenses relative to the treatment of the revenues associated with the recovery of these costs from customers within the ECR. PP&L Statement No. 7, p. 29. Indeed, in this proceeding, the Company has provided computational support for its ECR revenues and an analysis which computes the demand portion of the NUG revenue requirement responsibility for each class in keeping with the approach agreed to for such allocation at Docket No. M-00930406. In short, the Company adhered to a classification of a certain portion of NUG payments as demand related, for some purposes, but the Company failed to allocate its purchased power expense among the customer classes on a similar basis for the purpose of its cost-of-service study. Tr. at 626. This mismatch biases the Company's 12 CP cost-of-service study results. PPLICA Statement No. 7, p. 30.

An appropriate cost of service study analysis must classify the same portion of NUG expenses as demand related as are classified as demand related by the Company in its ECR revenue analysis contained in Schedule D-3 of this proceeding. PP&L Exhibit Future 1. To correct the Company's cost of service study, the retail portion of NUG purchased power expenses of approximately $220 million should be classified as 16.38% demand-related and 83.62% energy related. With this adjustment, the allocation of NUG expenses in the cost-of-service study is consistent with PP&L's treatment of NUG expenses within its ECR. PPLICA Statement No. 7, p. 31. Otherwise, in ignoring the demand/energy classification of NUG payments in the cost of service analysis and allocating 100% of the retail NUG payment cost to the rate classes on an energy basis, a greater than proportionate share of NUG expenses are allocated to high load factor customer classes such as Rate Schedule LP-5. Thus, the cost of service study assigns revenues associated with NUG payments on a less than proportionate basis, and it results in a lower rate of return on rate base being identified for rate schedule LP-5. In order to produce a reasonable estimate of each class' cost of service, this mismatch must be corrected. Id. at 32. PP&L is in agreement with the need to incorporate this correction. See PP&L Statement No. 7-R, p. 19.

c. PP&L's 12 CP Cost of Service Study Must be Adjusted to Allocate Costs Associated With EDI/IDI on a System-wide Basis.

The Company has anticipated that during the projected test year Economic Development Initiatives/Industrial Development Initiatives ("EDI/IDI") revenue credits to retail commercial and industrial customers of approximately $31 million (at present rates) will be realized. In its cost of service study, PP&L included the credits paid to customers as an offset to revenues in the rate schedules in which these customers reside, chiefly rate schedules LP-5, LP-6 and ISA. Tr. at 632. The effect was to reduce revenues for these rate schedules within the cost study. PPLICA Statement No. 7, pp. 33-34.

The Company's treatment of these credits is inappropriate because the provision of such credits benefits all customers on the system, not simply the customers who are advantaged by the credits and not simply customers who happen to take service on the same rate schedules as the customers receiving the credits. Id. at 34-35. This is especially so given the Company's belief, as stated in its EDI/IDI filing, that the IDI rider would have a positive rate impact on non-participating customers and provided a hedge against future costs being incurred by nonparticipating customers. PPLICA C.E. Exh. No. 5, p. 4. Similarly, with respect to its EDI rider, PP&L noted that non-participating customers would benefit from stabilized reduced costs in any future rate filings to the extent that the EDI/IDI rider customers remain in the service territory and expend their operations. Id. at 4-5. PP&L witness Farber agrees that the EDI/IDI programs benefit all customers currently as well. See Tr. at 636.

Given that it is clear that the intent of EDI/IDI program was to benefit all PP&L customers, a reasonable cost of service treatment of the EDI/IDI credits would assign the cost for those credits to all rate classes, rather than simply assigning the cost of the credits to the rate classes in which customers receiving the credits reside. PPLICA Statement No. 7, p. 36. OCA witness Johnson is in agreement with this conclusion. Tr. at 1348.

The flaw in the Company's methodology is exposed in examining the impact on Rate Schedule ISA, which contains only one customer who is receiving approximately $872,000.00 in EDI/IDI credits. Under the Company's cost of service methodology, the costs associated with this credit is assigned directly to Rate Schedule ISA; i.e., it is assigned directly to the customer receiving the credit. Consequently, the effect of the Company's absurd methodology would require recovery of the full amount of this credit directly from the customer receiving the credit, thereby negating the beneficial effect of the credit on both the individual customer and other non-participating customers. Id. at 36.

Moreover, to the extent that the Company does not allocate the cost of these credits to all customer classes, the Company implies that non-participating customers do not benefit from the EDI/IDI credit riders. Despite the fact that this is contrary to PP&L's stated purpose in offering these riders, if this were truly the Company's position, then the Company's assignment of the cost of these credits to all LP-4 and LP-5 customers, even though not all receive credits, is inconsistent. Id. at 37. In short, it is unreasonable for the cost of a program designed to benefit the system to be allocated to specific rate classes, not all of whose members participate in the programs from which the costs are derived.[7]

It is more appropriate for PP&L to treat these credits within the Company's 12 CP cost of service study in a manner that allocates the total cost to all customer classes. This recognizes the fact that the IDI/EDI credits benefit all customers, and it negates the propensity of PP&L's initial proposal to single out only certain non-participating customers (those in LP-4, LP-5 and ISA) from bearing the burden of the costs of these credits. Id. at 37-38. In addition, such treatment would be consistent with the Company's allocation of costs associated with customer assistance programs designed primarily for residential load. Tr. at 637.

d. Conclusion.

The Commission should approve and utilize the Company's 12 CP cost-of-service study as modified by PPLICA witness Baron. Id. at 39, Exhibit SJB-2. This 12 CP study, as modified, properly shifts the relative rate of return indices as compared to those presented in the Company's 12 CP study. Specifically, the PPLICA adjusted rate of return index for Rate Schedule LP-5 indicates that LP-5 customers are earning slightly above the average system rate of return. Increases also occur for Rate Schedules LP-4 and ISA, while the average system rate of return for the residential class decreases slightly but is still below the

[7]PP&L correctly spreads the "cost" of its interruptible rate program to all customer classes partially because that program benefits the system. For consistency and propriety, PP&L should also assign the "costs of the EDI/IDI program to all customer classes as a system benefit.

system average. Id. at 39-40, Figure 3; Exhibit SJB-2, pp. 1-2 (Attached as Appendix "A"). Witness Baron's computations also indicate that residential customers are receiving subsidies at present rates of almost $100 million, such subsidies being principally paid by Rate Schedules GS-1, GS-3 and LP-4. Id. at 41, Figure 4. It is with these rates of return and interclass subsidies in mind that PP&L's allowed increase should be allocated.

B. **OCA Witness Johnson's Proposal To Use A Peak And Average Cost Of Service Study Methodology Must Be Rejected.**

The OCA is recommending a peak and average production demand allocation methodology in this proceeding. As noted by PPLICA witness Baron, the peak and average methodology relies on the annual energy use of each customer class to compute the demand allocation factor in assigning the cost of fixed generating station investment to the classes. PPLICA Statement No. 7-R, p. 2. Based upon the use of this cost of service study, OCA Witness Johnson has assigned 61% of PP&L's production investment on the basis of annual energy use and 39% on the basis of class demands (during the three winter and two summer system peaks). Witness Johnson's recommendation effectively shifts away from demand responsibility by customer class and toward energy responsibility; this constitutes a radical change from the 12 CP methodology recommended by PP&L (and PPLICA) and previously adopted by the Commission for the Company. See Pennsylvania Public Utility Commission v. Pennsylvania Power & Light Company, 59 PaPUC 332, 394-98 (1985). The Commission must reject the OCA's radical, energy-oriented peak and average methodology for a number of reasons.

First, as recognized by PP&L and PPLICA, the 12 CP methodology is the most reasonable cost of service methodology for application to PP&L in this proceeding, given Commission precedent regarding PP&L. Id.

Second, OCA Witness Johnson's proposed peak and average methodology is premised upon the simplistic notion that system load factor determines the amount of PP&L investment allocated to energy use by PP&L's customers, with the remainder allocated to peak demand usage. This notion is simplistic because there is no factor implicit in his approach that considers the actual composition (e.g., peaking, baseload) of the generating plants on the PP&L system; therefore, Witness Johnson's method would produce the same allocation results even if all of PP&L's generating capacity were comprised of, for example, twenty (20) year old simple cycle combustion turbines or if all were ten (10) year old nuclear units identical to Susquehanna. PPLICA Statement No. 7-R, p. 4.

Third, Witness Johnson's proposed peak and average methodology is inconsistent with his proposal in the recent West Penn Power base rate case (Docket No. R-00942986). OCA Witness Johnson also proposed a peak and average methodology in that case; however, his proposal for West Penn incorporated an equal weighting between the peak and energy component of the allocator, consistent with the NARUC Electric Utility Cost Allocation Manual. OCA Witness Johnson has ignored that approach in this proceeding, thereby creating an underallocation of production and transmission investment to residential customers; indeed, if OCA Witness Johnson had utilized the NARUC peak and average approach in this proceeding, he would have allocated 3.2% more production and transmission investment to residential customers than PP&L's 12 CP methodology. PPLICA Statement No. 7-R, p. 6.

Fourth, OCA witness Johnson's peak and average methodology improperly allocates capital costs on an energy basis. The peak and average methodology is essentially a production demand allocation approach that relies on the capital substitution concept such that a substantial portion of production investment and associated expenses should be assigned to customer classes based on annual energy use. Id. at 7. In short, the peak and average methodology is premised on the assumption that utilities expend additional capital costs over and above the costs of peaking capacity in order to achieve fuel savings. The theory assumes (improperly) that the entire excess capital and fixed operation and maintenance costs of a baseload unit, over and above a combustion turbine unit, are solely related to fuel savings; however, this is simply not the case. As noted by OCA Witness Kahal, the Susquehanna capacity is uneconomic, thus a portion of its high capital costs is not related to fuel savings. Nonetheless, under Witness Johnson's methodology, these uneconomic Susquehanna costs are allocated to customer classes on the basis of energy under the clearly erroneous assumption that they provide energy-related fuel savings. Id. at 7-8.

Fifth, OCA Witness Johnson's peak and average methodology irrationally encourages customers to refrain from increasing consumption during PP&L's off-peak periods. Given that the peak and average methodology allocates increasing amounts of production demand costs (e.g., Susquehanna investment) to customer classes that consume more off-peak energy, the methodology provides a price signal to customers to refrain from increased off-peak energy usage on the PP&L system. Id. at 8. This price signal is inefficient for cost allocation purposes and has the effect of irrationally penalizing customers for increasing consumption during PP&L's off-peak periods. Id.

Sixth, OCA Witness Johnson's use of annual total energy in his analysis is inappropriate because it allocates costs based on off-peak kWh usage, which is unrelated to the economic choice between peaking and baseload plant. Even if one were to accept OCA Witness Johnson's capital substitution theory for cost allocation, the energy which is relevant for that cost allocation to the economic choice between peaking capacity and baseload capacity occurs in the first 2,531 hours on PP&L's load duration curve, not the entire 8,760 hours (in annual energy) utilized by OCA Witness Johnson in his analysis. The energy component of Witness Johnson's peak and average analysis should merely reflect the class contribution to energy in the first 2,531 highest demand hours on the PP&L system, as that level represents the break even point for both baseload and peaking capacity. See id. at 9-15.

Seventh, although PPLICA believes that OCA Witness Johnson's peak and average methodology must be rejected, if one were to accept his methodology and then apply an energy component which properly reflects the actual contribution of each class to demand during the highest 2,531 load hours on the system as represented by a weighted average demand factor, a production demand allocation for the residential class of 40.17% would be produced, which allocates 5% more investment to the residential customers than the 12 CP methodology recommended by PP&L and utilized in PPLICA Witness Baron's own analysis. Id. at 18. Residential customers would be worse off, as compared to an application of the 12 CP method, under a properly applied peak and average theory.

Finally, OCA Witness Johnson's cost-of-service analysis improperly allocates transmission plant on the same basis as generation plant. Even if one were to accept the rationale behind Witness Johnson's allocation of 61% of production demand costs on an energy basis, and 39% on a demand basis, there is no rationale to support the use of the same assignment factors for transmission plant. Transmission costs are entirely demand-related, and should not be allocated on an energy basis. Witness Johnson has failed to perform any capital substitution analysis to support his allocation factors for transmission plant and provides no basis for that allocation in his testimony.

For all these reasons, PPLICA asserts that OCA Witness Johnson's peak and average cost of service study methodology must be rejected. The OSBA (OSBA Statement No. 1-R, pp. 4-6) and PP&L (PP&L Statement No. 7-R, pp. 8-10) are in agreement with PPLICA in their opposition to the OCA proposal.

C. The Commission Should Establish Class Increases Based on a Goal of Achieving a 50% Reduction in Existing Subsidies for Each Rate Class at Proposed Rates Provided that No Rate Schedule, Including the Interruptible Rate Schedules, Should Receive an Increase in Excess of 1.5 Times the Authorized System Average Increase.

1. The PPLICA Revenue Allocation Approach Should Be Adopted by the Commission as it Provides a Systematic Movement of Class Rates Toward Cost of Service, Seeks to Reduce Subsidies by 50% and is Consistent with this Commission's Adherence to the Principle of Gradualism.

PPLICA recommends that the Commission establish class increases based on a goal of achieving a 50% reduction in existing subsidies (as identified in PPLICA witness Baron's application of the PPLICA Adjusted twelve CP methodology) for each rate class of proposed rates. As noted by PPLICA Witness Baron, "[t]he objective of this methodology is to reduce by 50% the dollar subsidies and proposed rates relative to the subsidies contained in present rates." PPLICA Statement No. 7, p. 48. However, PPLICA also believes that the concept of gradualism should be embraced by the Commission in order to avoid unnecessary rate shock. Consequently, PPLICA proposes that a cap be implemented such that no rate schedule, including the interruptible rate schedules, receive an increase in excess of 1.5 times the authorized system average increase. Id. PP&L is in general accord with such a cap. PPLICA C.E. Exhibit No. 6, p. 1; Tr. at 767.

PPLICA Exhibit SJB-3 (presented with the direct testimony of PPLICA Witness Baron, PPLICA Statement No. 7, also attached as Appendix "B" to this Main Brief), provides the results of the PPLICA-recommended methodology to reduce subsidies by 50% in proposed rates. As noted by PPLICA Witness Baron, the residential class would require an increase of approximately 24.31% in order to produce the system average rate of return of 10.17% at PP&L's proposed rate levels. Id. at 50. Similarly, witness Baron notes that the residential class is receiving a subsidy of $99.4 million at present rates; however, PPLICA proposes, in keeping with the principle of gradualism, to cap any increase in residential rates to 1.5 times system average increase. Id.

Even though PPLICA is recommending a 50% subsidy reduction approach, PPLICA does not recommend a decrease for any rate schedule in this proceeding. For example, even though on a straight cost of service basis, Rate Schedule GS-1 should receive a rate decrease, PPLICA proposes a zero increase to that rate class as a reasonable rate making approach. Id. at 51.

PPLICA Exhibit SJB-4 (attached as Appendix "C") shows the development of the PPLICA recommended rate schedule increases (assuming PP&L's $261 million increase is granted) utilizing the 50% subsidy reduction approach together with the limitation that no rate class receives an increase in excess of 1.5 times the system average increase. In addition, revenue decreases dictated by the cost of service based approach have been eliminated and the overall recommended increase is shown on the exhibit.

Under this approach, the residential class, LP-4 interruptible, and the LP-5/LP-6 interruptible classes all receive increases at the capped amount of 17.6% (again assuming that the Company's requested increase is granted). The increase recommended by PPLICA for Rate Schedule ISA is at 15.98% (substantially greater than the .15% proposed by the Company) and a number of other rate classes receive increases at the capped amount as well.

Id. at 52, 54, Table 2.[8] The rate of return indices at proposed PPLICA rates (again assuming the Company receives its entire rate request) indicate a systematic movement toward cost of service, while recognizing gradualism, that results in a reduction in interclass subsidization. In particular, as illustrated by PPLICA Witness Baron, under PPLICA proposed rates, virtually every class moves closer to a system average rate of return as compared to rate of return indices under present rates. Id. at 55, Figure 7. More importantly, the proposed subsidies under the PPLICA recommended distribution of the Company's increase are substantially reduced. Indeed, the residential subsidy drops from close to $100 million at present rates to approximately $60 million at PPLICA proposed rates. Id. at 56, Figure 8.

PPLICA has also provided a computation of the PPLICA-recommended allocation of a $20 million increase. See id. at 58, Table 3 and Exhibit SJB-5 (attached as Appendix "D"). This table provides a more realistic view of any approved distribution given the revenue requirement proposals offered by PPLICA, OTS and the OCA. This scaleback proposal again moves rates toward cost of service, attempts to minimize interclass subsidization, and is in keeping with the principle of gradualism.

In short, the PPLICA recommended distribution pursues a reasonable goal of achieving a 50% reduction in existing subsidies, buffers rate increases in concert with the policy of gradualism, and moves all rates closer to a system average rate of return. The

[8]If the Commission authorizes a lower increase than that requested by PP&L, the increase is shown on Table 2 would, of course, be adjusted.

PPLICA recommended distribution of any approved increase is a reasonable and pragmatic effort at equitable distribution and should be adopted by the Commission.[9]

2. PP&L's Revenue Allocation Proposal Must Be Rejected as PP&L's Failure to Apply the Principle of Gradualism to Interruptible Customers is Tantamountly Unjust in the Face of Recognized Competition.

PP&L has proposed to increase retail schedules by an average of 11.7% However, under PP&L's proposal, some rate schedules receive substantially greater increases than the system average; in particular, Rate Schedules LP-4 and LP-5 for interruptible customers are receiving increases in the range of 27% to 34%. In short, PP&L has proposed increases of nearly three times the system average increase for these interruptible customers. PPLICA Statement No. 7, p. 43.

PP&L's proposal indicates that the average LP-5 increase is 15.45%. However, as noted by PPLICA Witness Baron, there are in fact three distinct rate schedules contained within the LP-5 class: LP-5 firm customers, proposed LP-6 firm customers, and interruptible customers currently taking service on Rate Schedule LP-5. Thus, based on the Company's new design for interruptible service, the Company has proposed that the interruptible customers on Rate Schedule LP-5 will receive a 27% overall increase under the Company's rate design. PPLICA Statement No. 7, p. 45. Moreover, PP&L has posited through Witness Kasper that should the Company receive an increase less than its overall request, it would proportionately scale back its proposed distribution. Inexplicably, witness

[9]To the extent that the Commission authorizes an increase of less than $261 million, PPLICA recommends the use of relative dollar increases as a means of distributing any authorized increase in this proceeding. Id. at 57.

Kasper would not extend the scaleback for interruptible customers (i.e., PP&L Witness Kasper does not believe that the ratemaking principle of gradualism should apply to interruptible customers). Indeed, Witness Kasper indicates that PP&L's large interruptible industrial customers should receive a 22% increase under the Company's proposal, even if PP&L receives no overall revenue requirement increase in this proceeding. Tr. at 2203-03; see PPLICA Statement No. 7-R, p. 6.

PP&L's shoddy treatment of interruptible customers must be rejected for at least four reasons:

a. PP&L's effort to increase interruptible rates is in direct contravention to prevailing competitive trends.

PP&L's actions in seeking to substantially hike industrial rates are in diametric (and illogical) opposition to the prevailing trends in the electric industry. Electric utilities and public utility commissions on a national scale are making efforts to address competition in the electricity industry and the competitive alternatives that are available to large industrial customers.

For example, in recognition of these concerns, the Massachusetts Governor has recently called upon the Massachusetts Department of Public Utilities to require all electric utilities in Massachusetts to develop deregulation plans by the end of 1995. "Massachusetts Calls for Retail, Wholesale Competition," PUR Utility Weekly, June 2, 1995, Letter No. 3025, at 1. Similarly, the Pennsylvania Commission is aggressively pursuing issues regarding industry restructuring and has unequivocally recognized the need to address concerns regarding competition and large industrial customers. Investigation into Electric

Power Competition, Docket No. I-00940032; see, e.g., Lewistown Specialty Yarns, Inc. v. Pennsylvania Electric Company, Docket No. C-00924069, Commission Order entered May 24, 1994.

Electric utilities are also taking steps independently to provide competitive alternatives and competitive rates to their large customers. For example, PSI Energy is readying to file a proposed rider for qualifying businesses which provides industrials with a choice of suppliers in recognition of competition in the industry. "PSI's New Economic Development Riders Offer Industrials a Choice of Suppliers," Industrial Energy Bulletin, June 2, 1995 at 1. Similarly, two Massachusetts utilities, New England Electric System and Eastern Utilities Associates, have joined a coalition seeking to harness the benefits of increased competition in the electric industry. "Massachusetts Industrials Join Broad Coalition in Support of Rhode Island Restructuring Plan," Industrial Energy Bulletin, June 2, 1995 at 4. Recently, the Detroit Edison Company has also effected sole supplier contracts with major manufacturers reducing rates by approximately 15%. Bethlehem Steel Statement No. 1, p. 5.

PP&L itself has recognized the competitive alternatives available to large customers in this proceeding. Tr. at 762-65. Like PP&L, Louisiana Power & Light has also recognized that such customers may be at risk given their ability to use alternative resources; however, unlike PP&L, Louisiana Power & Light sought and received flexibility from the Louisiana Public Service Commission at Docket No. U-20925 to offer discounts to these "at risk" customers. Conversely, PP&L has sought to increase rates for large industrial interruptible customers by upwards of 35%. Clearly, in the face of this national trend, PP&L's absurd treatment of its interruptible customers in this proceeding must be viewed with great skepticism and is viewed, at least by PPLICA, with great disbelief.

b. PP&L's proposal to substantially increase interruptible rates contravenes all notions of gradualism and avoidance of rate shock.

PP&L's proposal to increase interruptible rates by 27% to 34% under its original proposal (and by 22% even if there is no increase granted in this proceeding), utterly fails to comply with the Commission-embraced principle of gradualism.

This Commission has routinely recognized that in order to avoid rate shock, rate increases must be phased in as per the principle of gradualism. See Pennsylvania Public Utility Commission v. Philadelphia Electric Company, 74 PaPUC 1, 211-12 (1990). As the Commission has specifically stated in the past, "[i]t is well established in utility ratemaking that class cost of service studies serve as a guide . . . in the formulation of rate structure. Other factors such as gradualism and competitiveness must be considered as well." Pennsylvania Public Utility Commission v. National Fuel Gas Distribution Corporation, 73 PaPUC 552, 621 (1990) (emphasis added). Indeed, the Commission has specifically recognized the principle of gradualism in identifying and adopting proper rate structure proposals. See Pennsylvania Public Utility Commission v. Western Pennsylvania Water Company, 95 PUR4th 470, 515-16 (1988); Pennsylvania Public Utility Commission v. Pennsylvania-American Water Company, 97 PUR4th 469, 507-08 (1988).

PP&L has itself recognized and alleged that it supports gradualism in ratemaking. PP&L Statement No. 8, p.5; PP&L Statement No. 1, p.3. Indeed, PP&L witness Kasper has acknowledged that achieving a 100% system average rate of return is often burdensome on the customer to achieve in a single step (Tr. at 765-66), thus PP&L has "capped" rate class increases at 1.5 times the system average increase. PPLICA C.E. Exhibit No. 6. Despite this, PP&L obstinately refuses to acknowledge that its proposed increases to interruptible rates of 27% to 35% (28% to LP-5 interruptible customers, Tr. at 774), nearly 3 times the requested system average increase, violate the Commission's adherence to the principle of gradualism, even through PP&L acknowledges that a 20% increase to a single rate class would violate the principle of gradualism. Tr. at 775.

It is clear that the Commission has embraced the concept of gradualism in approving the distribution of revenue increases. It is equally clear that PP&L's proposal to increase the rates of interruptible customers by nearly 35% (based on its original proposal and by 22% even if no increase is granted); i.e., nearly three times the system average increase, flaunts the Commission's adherence to the principle of gradualism and contravenes PP&L's own alleged support for the gradualism concept.

c. PP&L's proposal to increase interruptible rates will negatively impact individual industrial customers.

In addition to this contempt for gradualism and the realities of competition, PP&L's proposal(s) regarding interruptible rates evidences a personal contempt for industrial customers that is astounding in the face of the impact testimony provided by PPLICA member companies in this proceeding. For many of these companies, electricity costs represent upwards of 70% of total production costs. See PPLICA Statement No. 1, p. 3 (BOC Gases); PPLICA Statement No. 2, p. 4 (Air Products). Obviously, an increase of the magnitude proposed by PP&L will seriously impinge upon these companies' respective costs of production and may ultimately hasten their departure from the PP&L service territory and concomitant losses to the local and state economies.

Similarly, many of these companies served by PP&L have plants in other states which are essentially in competition with the plants here. See PPLICA Statement No. 3, pp. 5-6 (Donnelley); PPLICA Statement No. 4, pp. 4-5 (Hershey). Many of these companies must remain globally competitive as well. See, e.g., PPLICA Statement No. 5, p. 4 (Thomson). To the extent that PP&L significantly raises interruptible rates under which these companies receive electricity, their ability to make their Pennsylvania investments profitable enough to outpace sister plants and competitors will be seriously impaired. Again, the risk of loss to the economy of the Commonwealth and the risk of loss for the PP&L system is enhanced.

Finally, to the extent that PP&L pursues its campaign to hike interruptible industrial rates, individual PPLICA members can only be left to assume that the metaphorical welcome mat has been pulled out from under them. This is alarming not only because it indicates a total reversal of PP&L's position from 1992 when it first proposed its Optional Interruptible Power service, but because these companies may be left no recourse but to pursue any and all competitive alternatives. See PPLICA Statement No. 6, pp. 7-9 (Armstrong).

Pennsylvania can ill afford to risk losing the 26,000 jobs, $230 million in local purchases, and $64 million in state and local taxes that PPLICA members provide. Similarly, other PP&L ratepayers could not afford to risk losing the $105 million annual contribution that PPLICA members make on the PP&L system. PPLICA Statement No. 7, pp. 5-6. PP&L's proposal to jack-up industrial interruptible rates must be rejected, especially given the impact that such a proposal (if approved) would have on individual

PPLICA members and, concomitantly, other PP&L ratepayers and the economy of Pennsylvania. PP&L's proposal is especially chafing given that PP&L recognizes that business closure or contraction still exist in today's markets for industrial customers. Tr. at 845-46.

d. PP&L's backhanded attempt to compare its current <u>proposal to historic rates is patently absurd.</u>

PP&L has added insult to injury with its assertion that its proposed interruptible increases are <u>not</u> large relative to previous rates interruptible customers paid prior to 1992 and that interruptible industrial customers will essentially receive no increase at all in this proceeding relative to rate levels established in the Company's last base rate case. These assertions are irrelevant, irrational, disingenuous, and must be rejected. The fact that the mix of firm and interruptible rates on which PP&L's current interruptible customers took service prior to 1992 may well be comparable to those that the Company is proposing for its LP-5 interruptible rate option in this proceeding is irrelevant. The Company is proposing a 27% average increase for LP-5 interruptible customers based on present rates. Any comparison to rates paid by similarly situated industrial customers in the past, during any period, as compared to proposed rates does not provide any substantial basis upon which a decision can be rendered in this proceeding.

Furthermore, the Company's assertion that interruptible industrial customers are essentially receiving no increase at all in this proceeding relative to rate levels established in the Company's last base rate case (in 1985) warrants an equally deft dismissal. PP&L, through its witness Kasper, is comparing customers who for the most part took firm service to customers who are now subject to interruption. That alone renders this comparison meaningless. In addition, comparing rates paid by these firm customers in 1986 to interruptible rates for these same customers in 1995 is equally irrelevant. PP&L's disingenuous comparisons must be ignored.

Indeed, PP&L witness Farber has admitted that the same conditions that existed regarding business risks, competitive alternatives and pressures which led to PP&L's original Optional Interruptible Power filing exist today. Tr. at 1694. It is therefore grossly inconsistent for PP&L to now seek such a substantial increase in industrial rates.

e. Conclusion.

PP&L's proposal to effect a shocking increase of upwards of 35% to industrial interruptible customers (and an increase of 22%, even if no revenue increase is granted to the Company) must be rejected. The proposal belies the competitive trend recognized nationally and locally by public utility commissions as well as individual electric utilities. The proposal is in contempt of all notions of gradualism as they have been recognized by this Commission and PP&L itself. The proposal represents a serious and unwarranted threat to individual PPLICA members. Finally, PP&L's attempts to normalize the magnitude of its behemoth increase by comparing it to firm rates that were paid in the past is disingenuous at best. The Commission must not allow PP&L to skewer industrial customers in the face of these realities.

3. PP&L's Proposed Distribution Fails to Adequately Move Rates Toward the System Average Rate of Return and Fails to Adequately Address Interclass Subsidization.

As illustrated by PPLICA Witness Baron, a comparison of interclass subsidies received by and/or paid by each of PP&L's major rate classes under present and proposed rates using the PP&L's 12 CP cost-of-service study indicates that the residential class would continue to receive a substantial subsidy. PPLICA Statement No. 7, p. 47, Figure 6. Similarly, though the Company does move class rates of return towards system average level, it has not done so in a systematic fashion.

The residential class has been increased in a fashion such that the rate of return index still remains substantially below cost of service, while the increased rates for Rate Schedule LP-5 are such that its proposed rates now greatly exceed the cost of service. PPLICA Statement No. 7, p. 46, Figure 5. PP&L chose to move LP-5 much closer to the system average rate of return and much more quickly than the residential class on both an absolute and relative rate of return basis. Tr. at 761. PP&L has proposed this, even though it recognizes that LP-5 customers typically have production facilities in other states and are capable of self-generation, bypass or cogeneration. Tr. at 762-65; PP&L statement No. 8, p. 5.

In addition, PP&L has also accepted that its wholesale rates will decline by 10.5% on January 1, 1996, and based on its allocation and rate design, even if no increase is granted, the gap between PP&L's wholesale rates and LP-5 rates will increase further. Tr. at 816-17. In short, retail rate levels for customers of comparable size to wholesale customers will increase greatly. Both PP&L's wholesale tariff and Schedule LP-5 serve customers taking service at 69,000 volts or higher. If PPLICA members received service under the wholesale rate (a market rate), they would be charged $97 million annually, or over 8% less than current rates (which includes interruptible load) and 22% less than they will pay under PP&L's proposed rates. PPLICA Statement No. 7, p. 8. It is clear that PP&L's proposal is not competitive as compared to PP&L's wholesale tariff. Id. Similarly, PP&L's own internal estimate of benchmark prices for 1995 to 2000 indicates that PP&L's proposed LP-5 and LP-6 rates will exceed market prices by 120% in 1995. Id. Thus, in addition to its failure to effect a more systematic movement towards cost of service, and substantial reductions in interclass subsidization, the PP&L proposal essentially ignores the accepted need to address competition.

D. The Commission Should Approve the PPLICA-Recommended Rate Design for the LP-5/LP-6 Interruptible Rate Schedule.

Under the Company's proposal, there would be essentially, four different rate schedules contained within the current LP-5 revenue class: LP-5 firm, LP-5 interruptible, LP-6 firm, and LP-6 interruptible. Though the Company has historically identified a single LP-5 revenue class for cost-of-service and other purposes, the current LP-5 tariff actually includes two separate and distinct rate schedules, LP-5 firm and LP-5 interruptible. These are essentially two different rate schedules providing service to two different types of customers. PPLICA Statement No. 7, p. 59. In addition, the Company has proposed an additional firm rate schedule and an additional interruptible rate schedule for customers whose average demand exceeds 10,000 kW (LP-6). In short, under the Company proposal, there will be four different LP-5/LP-6 rates (but all are under the LP-5 revenue category).

The Company has eliminated the separate interruptible tariff under which many PPLICA members took service and has replaced it with an "interruptible credit" which is applied to firm rates (on both LP-5 and LP-6, as proposed). That credit is based on the cost of a new combustion turbine peaking unit; PP&L has proposed a credit of $6.00/kW per month and $8.00/kW per month, depending upon notice requirements. PP&L has proposed to alter the interruptible rate design by removing the currently applicable demand/energy blocked rates. See PP&L Exhibit OGK-1. PP&L's proposed design is essentially a flat kW rate with an adjustment for load factor. Tr. at 2215. Under the current tariff, a demand charge is applicable to the billing kW and then two energy blocks (plus the ECR) apply. PPLICA C.E. Exhibit No. 4. As recognized by PP&L, the current design is more sensitive to load factor, thus PP&L's proposed design charges (applying a flat/kW credit) lead to the substantial increase proposed for interruptible customers in this proceeding. Tr. at 804-06. PP&L has also proposed a 500 MW cap on interruptible load. See PP&L Exh. OGK-1. Given that the effective amount of interruptible load for the cap has been identified as 460 MW, only 40 MW of interruptible load are available. Tr. at 810.[10]

As noted before, the overall LP-5 revenue increase is shown to be 15.45% in the Company's filing as compared to the overall system average increase of 11.7%; however, once the LP-5 revenue class is disaggregated (consistent with PP&L's proposal), it becomes apparent that the Company's proposal for interruptible customers is to increase rates on average of 27%. PPLICA Statement No. 7, p. 60. In short, PP&L proposed an increase of 15.45% for the LP-5 rate class; however, because of design changes proposed by PP&L with respect to interruptible rates, PP&L's proposed increase of 15.45% included a hidden increase to interruptible customers of over 27% under LP-5.

PPLICA adamantly opposes PP&L's interruptible rate design changes. By assessing a flat kW credit without sensitivity to the current demand/energy consumption characteristics, PP&L has effectively transformed its interruptible service into a firm service rate with a load insensitive credit. This represents a dramatic change in rate design philosophy and causes an unprecedented increase in rates without any meaningful justification. Indeed, as aforementioned, the size of the increase proposed by PP&L as a result of these design

[10]Though PP&L did indicate that existing interruptible customers could add incremental load beyond the cap (tr. at 811), this should be clarified in the event that the Company's rate design is adopted.

changes is in diametric opposition to the current competitive trends, the principle of gradualism, and the recognized sensitivities of this state's economy. The PUC must therefore not allow PP&L to implement this unprecedented change in rate design.

PPLICA recommends three separate and distinct rate schedules: LP-5 firm, LP-6 firm, and LP-5/6 interruptible. The Company's basic design for these two proposed firm rates schedules is reasonable; however, the PPLICA-recommended revenue increases should be utilized to establish the revenue requirements for each of these two schedules.

PPLICA asserts that it is appropriate to retain the existing LP-5 interruptible rate structure in this proceeding; i.e., PPLICA proposes to apply the 1.5 times the system average increase for the interruptible rate directly to the existing LP-5 interruptible rate design, resulting in an overall revenue increase for these interruptible customers of 17.55% (if the Company received its entire increase). Id. at 62. This is a substantial increase relative to the increases proposed by PPLICA with respect to P-5 and LP-5 firm rates and with respect to other customer classes like GS-1 and GS-3. However, this increase unlike the PP&L proposal regarding interruptible rates, complies with the principle of gradualism and recognizes the current competitive state of the electric supply industry. This current interruptible rate structure is to be identical for both LP-5 and new LP-6 customers, thus the LP-5/LP-6 interruptible customers should be deemed to comprise one rate schedule. Id. at 63. PPLICA Exhibit SJB-6 (attached as Appendix "E") illustrates PPLICA's proposed rate design under the assumption that the Company is authorized its total requested increase, thus the LP-5 revenue class (all three proposed distinct rate schedules LP-5 firm, LP-6 firm, LP-5/LP-6 interruptible) would receive a 10.9% increase. Id.[11]

[11]Under the approach that PPLICA recommends in this proceeding (to apply revenue increase to the existing LP-5 interruptible rate schedule), there is, inherent in the rate design an interruptible credit that is approximately the same as that proposed by the Company. See PPLICA Statement No. 7, p. 64.

E. PP&L's Valuation of Interruptible Rates Under the Proposed "Resource Value Approach" Must be Rejected.

As aforementioned, the Company has, consistent with its cost of service study, and - proposed rate design utilized a "resource value approach" which assumes that interruptible load is a substitute for peaking capacity. Under this proposal, interruptible customers would be priced at firm service rates less a credit equal to the value that those customers provide as interruptible customers on an equivalent peaking capacity basis to the PP&L system. Under this approach, interruptible customers pay rates that are based on a "value" while other PP&L customers pay rates based on embedded costs. PPLICA Statement No. 7, p. 65.

Put another way, the Company's methodology assumes that interruptible load on the PP&L system is a resource to be purchased by the Company, rather than a low reliability service offered by the Company. PPLICA wholly opposes the treatment of interruptible sales in a manner different from other sales. Interruptible customers should be entitled to cost of service based rates and not subject to pricing based upon the cost of combustion turbine capacity or revenues received from capacity credit sales. These approaches reflect a market-based approach that is inherently discriminatory to interruptible customers who desire to purchase lower quality power. As such, PPLICA is adamant that this Commission must decide that interruptible customers are entitled to the same pricing basis as afforded all other customers on the PP&L system.

Otherwise, under PP&L's framework, interruptible customers who desire to purchase lower quality power are being told that they are in effect buying firm power but selling peaking capacity back to PP&L, and since the interruptible customers must sell their capacity back to PP&L, the Company is monopsonist in this transaction and wields the concomitant power of a monopsonist. Id. at 67.

PP&L's approach to the valuation of interruptible sales is faulty for other reasons as well. Specifically, PP&L's valuation of interruptible load is incorrect since PP&L has failed to include an adjustment for active load management which would raise the value of interruptible load to reflect a reserve margin which is avoided when interruptible load is on the system. Id. This active load management adjustment would increase the capacity value of each kW of interruptible load by a factor of 1.19. Given that PP&L includes interruptible load in its PJM capacity at a rate of 1.19 kW and relies on this active load management to adjust interruptible load in its resource plans, the capacity equivalent value of interruptible load that PP&L has proposed to use should reflect this adjustment. Id. Thus, if the Commission were to adopt PP&L's treatment of interruptible load, the $300.00 per kW value PP&L has ascribed to that load should be increased to $357.00 per kW to reflect this active load management factor. Id.

In addition, there are other measures of resource value that may better reflect interruptible load value. For example, the official PJM capacity deficiency rate of $73.00 per kW year is a measure of the value of interruptible on the PP&L system as well. After adjustment for the active load management factor, the annual value of capacity using the PJM capacity deficiency rate would be $86.87 per kW year or $7.24 per kW month. Id. at 68.

In any event, PPLICA opposes the use of the resource value approach in analyzing the proper interruptible rate. As aforementioned, PPLICA has recommended that a specific increase be applied to the existing interruptible rate for LP-5 and LP-6 customers that is equal to 1.5 times the system average increase. Id. at 69. In addition, an appropriate interruptible rate should be based on cost of service principles such that interruptible customers face the same pricing and costing mechanism and framework that is used to establish rates for other customer classes. This is required since industrial customers are not permitted to "sell" their capacity resources to other utilities or to other retail customers and because industrial customers are not free to purchase electricity from other utilities. Id. PP&L's alternative "resource value approach" must be rejected.

F. OCA Witness Johnson's "Resource Value" Approach for the Treatment of Interruptible Load Within His Cost of Service Study is Inappropriate and Must Be Rejected.

OCA Witness Johnson accepts the Company's flawed "resource value" approach for the treatment of interruptible load within his cost of service study, however, Witness Johnson also incorporates misguided market-based adjustment to the resource value associated with interruptible load. It is entirely inappropriate to use a "resource value" approach, and OCA Witness Johnson's market-based adjustment to that approach further undercuts the questionable value.

The Company proposed a $300 per kW plant-in-service credit equating to approximately $3.00 per kW per month of interruptible load under contract. Witness Johnson has based his analysis on an interruptible credit of $1.25 per kW per month based on an alleged assessment of the current market value of peaking capacity on the PJM system. Witness Johnson then proposed a $15.00 per kW value credit to calculate the rate base offset for interruptible load.

As noted by PPLICA Witness Baron, Witness Johnson's reported cost of service study results are incorrect in any event, but more importantly, their basis in a market-based valuation for interruptible rates on the PP&L system is inappropriate because interruptible customers are required to sell their peaking capacity to PP&L, a monopsonist with respect to this type of transaction -- no market exists for the sale of this capacity. Thus, it is entirely unreasonable for Witness Johnson to impute a market-based valuation for peaking capacity given that these interruptible customers are not permitted to sell their peaking capacity (in the form of interruptible load under the resource value framework) to PJM or other utilities.

PPLICA Statement No. 7-R, p. 23. To value this peaking capacity on a market basis utterly fails to protect interruptible customers from the reality of the utility's monopsony power. OCA Witness Johnson's methodology must be rejected.

G. Sierra Club Witness Biewald's Recommendation to Require a Certificated Comprehensive Energy Audit of Large Business Customers Prior to Receiving Any "Discounts" from PP&L Must be Rejected.

Sierra Club recommends that a certified comprehensive energy audit must be performed on any industrial customer before it receives a discount rate. Sierra Club Statement No. 1, p. 29. This absurd proposal must be rejected as there is no rationale to require energy audits for industrial customers, while not requiring them for any other customer. PPLICA Statement No. 7-R, p. 24.

To the extent that the Sierra Club proposal has any rational basis, it should be considered in the context of a DSM case. The Commission's ongoing investigation into electric utility DSM programs at PUC Docket No. I-00900005 is the appropriate forum for the Biewald proposal (subject, of course, to the ultimate resolution of the PUC's demand-side cost recovery order which is the subject of an appeal brought by the Commission before the Supreme Court of Pennsylvania at No. 0164 M.D. Allocatur 1995).

VI. CONCLUSION

PPLICA members consume over 2.4 billion kWh per year on the PP&L system at a cost of $105 million. PPLICA members employ tens of thousands of Pennsylvanians and contribute nearly $230 million to the local and state economy and over $64 million in local and state taxes. But these contributions (to the Commonwealth and the PP&L system) are not guaranteed. PP&L members are engaged in competitive processes, businesses and markets. Competitively priced electricity is extremely important, and sometimes critical, to their competitive viability.

Consequently, PPLICA members are no less than shocked by the rate design and rate allocation proposals that PP&L has made with respect to industrial interruptible rates. Those proposals endeavor to increase rates to industrial customers by over 27% and by 22% even if PP&L is granted no increase. PP&L's proposal manifests a complete denial of the realities of competition, ignores any reasoned adherence to the principle of gradualism, and belies any sensitivity to the competitive pressures faced by industrial customers. PP&L's proposals must be rejected.

Specifically, PP&L's proposed interruptible rate design for schedules LP-5 and LP-6 must be rejected. The PUC should approve the PPLICA recommendation to maintain the current LP-5 interruptible rate design for both LP-5 and proposed LP-6 customers. Toward that end, PP&L's proposal to determine interruptible rates under a resource value approach must be rejected in favor of a cost of service approach.

The PUC should also adopt the following PPLICA recommendations:

- A rate of return on common equity of 10.85%;

- The use of historic capital structure data as opposed to PP&L's proposal to utilize a structure based on a speculative equity issuance;

- Adjustments to PP&L's proposed revenue requirement resulting in an allowed revenue requirement of no more than $24 million;

- The adoption of a 12 CP cost of service study methodology as modified by PPLICA;

- The PPLICA-recommended revenue allocation proposal;

- A rejection of PP&L's proposal to automatically recover reduced revenues associated with the loss of capacity sales to JCP&L;

- The inclusion of off-system revenues in base rates at test year levels and the rejection of PP&L's proposal to include those revenues with the ECR.

WHEREFORE, the PP&L Industrial Customer Alliance respectfully requests that the Commission adopt PPLICA's conclusions and recommendations as set forth in this Main Brief.

Respectfully submitted,

McNEES, WALLACE & NURICK

By [signature]
David M. Kleppinger
Derrick P. Williamson
100 Pine Street
P. O. Box 1166
Harrisburg, PA 17108-1166
(717) 237-5214

Counsel for PP&L Industrial
Customer Alliance

Dated: June 16, 1995

APPENDIX A

PPLICA Adjusted 12 CP Cost-of-Service Study
Pennsylvania Power & Light
Cost Allocation Details - Future Test Year Ended 9/30/95
Summary

	Input	Allocation	Output	Total Pennsylvania Jurisdiction	RS	RTS	GS-1	GS-3	LP-4
Rate Base									
Plant-in-Service									
Production			P10	5,021,440	1,927,589	91,807	253,326	1,154,196	653,902
Transmission			P20	365,607	140,881	6,710	18,515	84,356	47,792
Distribution			P30	2,532,998	1,477,443	55,187	198,276	409;887	137,807
Other			POT1	276,661	137,175	4,985	17,476	51,027	26,539
Common Plant (Acct. 186)			P97T	0	0	0	0	0	0
Total Plant-in-Service			P00	8,196,706	3,683,087	158,689	487,594	1,699,466	866,038
Depreciation Reserve									
Production			A10	1,396,759	536,176	25,537	70,465	321,050	181,889
Transmission			A20	116,155	44,759	2,132	5,882	26,800	15,184
Distribution			A30	867,290	508,263	18,327	68,041	134,377	44,785
General Plant			A88	89,267	44,261	1,608	5,639	16,464	8,563
Intangible Plant			A95	7,651	3,794	138	483	1,411	734
Total Depreciation Reserve			AOST	2,477,122	1,137,252	47,743	150,510	500,103	251,154
Amortization Reserve			A97T	0	0	0	0	0	0
Total Depreciation & Amort. Reserve			A00	2,477,122	1,137,252	47,743	150,510	500,103	251,154
Total Net Plant in Service			P01	5,719,584	2,545,836	110,947	337,083	1,199,363	614,884
Total Subtractive Adjustment			PLEDE	903,062	372,752	16,894	49,505	198,752	107,580
Total Additive Adjustment			PLADD	12,378	4,752	226	624	2,845	1,612
Total Net Original Cost Rate Base			NOP	4,828,900	2,177,836	94,279	288,203	1,003,456	508,917
Working Capital									
Fuel Inventory									
Wholly-Owned Coal			W10A	62,590	22,232	793	3,106	13,710	9,082
Other Non-Nuclear			W10B	26,124	9,279	331	1,296	5,722	3,791
Nuclear Fuel			W10C	0	0	0	0	0	0
Total Fuel			W10T	88,714	31,511	1,124	4,403	19,432	12,873
Other			W0T1	99,563	42,415	1,920	5,575	21,576	11,370
Total Working Capital			W00	188,277	73,926	3,044	9,978	41,008	24,243
Total Rate Base			RBX	5,017,177	2,251,761	97,324	298,181	1,044,463	533,160

PPLICA Adjusted 12 CP Cost-of-Service Study
Pennsylvania Power & Light
Cost Allocation Details - Future Test Year Ended 9/30/95
Summary

	LP-5	LPEP	ISA	GH	SL/AL	Standby
Rate Base						
Plant-in-Service						
Production	723,992	21,930	62,510	120,778	9,429	1,980
Transmission	*52,914*	*1,241*	*3,537*	*8,827*	*689*	*145*
Distribution	57,781	1,840	5,081	52,466	137,080	151
Other	27,305	829	2,359	5,629	3,263	75
Common Plant (Acct. 186)	0	0	0	0	0	0
Total Plant-in-Service	861,993	25,840	73,486	187,701	150,462	2,351
Depreciation Reserve						
Production	201,385	6,100	17,388	33,596	2,623	551
Transmission	16,811	394	1,124	2,804	219	46
Distribution	18,847	597	1,655	17,201	55,147	49
General Plant	8,810	267	761	1,816	1,053	24
Intangible Plant	755	23	65	156	90	2
Total Depreciation Reserve	246,609	7,382	20,992	55,573	59,132	672
Amortization Reserve	0	0	0	0	0	0
Total Depreciation & Amort. Reserve	246,609	7,382	20,992	55,573	59,132	672
Total Net Plant in Service	615,384	18,458	52,494	132,128	91,330	1,678
Total Subtractive Adjustment	114,341	3,445	9,834	21,230	8,418	312
Total Additive Adjustment	1,785	54	154	298	23	5
Total Net Original Cost Rate Base	502,827	15,066	42,814	111,195	82,936	1,371
Working Capital						
Fuel Inventory						
Wholly-Owned Coal	11,003	286	1,038	1,104	214	22
Other Non-Nuclear	4,592	119	433	461	89	9
Nuclear Fuel	0	0	0	0	0	0
Total Fuel	15,595	405	1,471	1,565	303	32
Other	11,773	359	1,001	2,362	1,180	33
Total Working Capital	27,368	764	2,472	3,927	1,483	64
Total Rate Base	530,195	15,831	45,286	115,122	84,418	1,436

PPLICA Adjusted 12 CP Cost-of-Service Study
Pennsylvania Power & Light
Cost Allocation Details - Future Test Year Ended 9/30/95
Summary

	Input	Allocation	Output	Total Pennsylvania Jurisdiction	RS	RTS	GS-1	GS-3	LP-4
Operating Revenues At Present Rates									
Sale of Electricity									
Rate Revenue	RR			2,263,602	909,213	20,360	165,977	520,355	281,626
Energy/Fuel Cost Revenue	ECR			(21,487)	(7,008)	(248)	(1,005)	(4,491)	(3,377)
State Tax Adj Surcharge	STAS			0	0	0	0	0	0
Spec Base Rate Credit Adj	SBRCA			(38,084)	(15,093)	(338)	(2,755)	(8,692)	(4,896)
Interruptible Revenue									
Revenue Credits				23,273	0	0	0	0	2,652
Interruptible Expense				(23,273)	(8,934)	(426)	(1,174)	(5,349)	(3,031)
Net Interruptible Credits				0	(8,934)	(426)	(1,174)	(5,349)	(379)
Economic/Industrial Development									
Revenue Credits				30,624	0	0	0	3,279	13,319
EDI/IDI Expenses				(30,624)	(13,744)	(594)	(1,820)	(6,375)	(3,254)
Net EDI/IDI				(0)	(13,744)	(594)	(1,820)	(3,096)	10,065
Total Sale of Electricity			RRT	2,204,031	864,434	18,754	159,223	498,726	283,039
Annualization	ANN			25,615	8,192	367	3,393	5,340	4,745
Late Payment Charges			R11	7,074	3,508	27	1,314	1,528	377
Total Adj'd Sale of Electricity			RRTT	2,236,720	876,134	19,149	163,930	505,595	288,160
Other Operating Revenues			ROOT	165,535	63,272	2,357	8,694	35,469	22,223
Total Operating Revenues			ROT	2,402,255	939,406	21,506	172,623	541,064	310,384

PPLICA Adjusted 12 CP Cost-of-Service Study
Pennsylvania Power & Light
Cost Allocation Details - Future Test Year Ended 9/30/95
Summary

	LP-5	LPEP	ISA	GH	SL/AL	Standby
Operating Revenues At Present Rates						
Sale of Electricity						
Rate Revenue	268,654	8,665	21,238	44,746	21,591	1,177
Energy/Fuel Cost Revenue	(4,364)	(116)	(422)	(375)	(72)	(9)
State Tax Adj Surcharge	0	0	0	0	0	0
Spec Base Rate Credit Adj	(4,678)	(144)	(367)	(743)	(358)	(20)
Interruptible Revenue						
Revenue Credits	16,996	0	3,626	0	0	0
Interruptible Expense	(3,356)	(102)	(290)	(560)	(44)	(9)
Net Interruptible Credits	13,640	(102)	3,336	(560)	(44)	(9)
Economic/Industrial Development						
Revenue Credits	13,154	0	872	0	0	0
EDI/IDI Expenses	(3,236)	(97)	(276)	(703)	(515)	(9)
Net EDI/IDI	9,918	(97)	596	(703)	(515)	(9)
Total Sale of Electricity	283,170	8,207	24,381	42,366	20,602	1,130
Annualization	4,973	0	0	(1,014)	(381)	0
Late Payment Charges	133	0	0	135	52	0
Total Adj'd Sale of Electricity	288,276	8,207	24,381	41,486	20,273	1,130
Other Operating Revenues	25,997	692	2,423	3,099	1,253	55
Total Operating Revenues	314,272	8,899	26,804	44,585	21,527	1,185

PPLICA Adjusted 12 CP Cost-of-Service Study
Pennsylvania Power & Light
Cost Allocation Details - Future Test Year Ended 9/30/95
Summary

	Input	Allocation	Output	Total Pennsylvania Jurisdiction	RS	RTS	GS-1	GS-3	LP-4
Operating Expenses									
Operating & Maintenance Exp.									
Production									
Fuel			EOPF1	431,704	153,338	5,471	21,424	94,561	62,645
Power Purchases			EOPP1	252,511	90,992	3,455	12,569	55,801	35,966
Other Production			EOP01	297,079	110,334	4,706	14,881	66,887	40,610
Total Production			EE10T	981,294	354,664	13,632	48,873	217,250	139,221
Transmission			EE20	10,487	4,026	192	529	2,410	1,366
Distribution			EE30	92,936	51,716	2,092	7,738	15,501	5,467
Other Operating & Maint. Expenses			EOMT1	288,210	157,205	4,504	19,185	46,023	24,843
Total Operating & Maintenance Exp.			EE00T	1,372,927	567,610	20,420	76,326	281,185	170,897
Depreciation Expense									
Production			ED10	231,599	88,904	4,234	11,684	53,234	30,159
Transmission			ED20	7,753	2,988	142	393	1,789	1,013
Distribution			ED30	70,147	41,443	1,513	5,654	10,579	3,279
Other Depreciation Exp.			ED88	11,298	5,602	204	714	2,084	1,084
Total Depreciation Expenses			ED0ST	320,797	138,936	6,093	18,444	67,686	35,536
Amortization Expenses (Acct. 406)			ED97T	0	0	0	0	0	0
Total Depreciation & Amortization			ED00	320,797	138,936	6,093	18,444	67,686	35,536
Miscellaneous Allowable Expenses			TX89	(29,674)	(11,378)	(540)	(1,497)	(6,816)	(3,871)
Taxes									
- Other Capital Stock			ET1	30,553	13,600	593	1,801	6,407	3,285
- Other w/o Cap Stock			ET001	57,585	26,403	1,071	3,464	11,592	6,048
Deferred Income Taxes			TXT	(15,424)	(3,234)	(219)	(418)	(4,396)	(3,032)
Net Investment Tax Credit			TX91	(8,625)	(3,876)	(167)	(513)	(1,788)	(911)
Gross Receipts Tax			TXG	98,416	38,550	843	7,213	22,246	12,679
PA & Federal Income Taxes			TSF1	209,078	52,671	(3,567)	25,885	64,140	36,290
Total Taxes			TEX1	371,583	124,114	(1,447)	37,431	98,201	54,358
Total Operating Expenses			TEXP1	2,035,633	819,283	24,526	130,705	440,255	256,920
Return			PRERTN	366,622	120,123	(3,020)	41,919	100,808	53,464
Total Rate Base			RBX	5,017,177	2,251,761	97,324	298,181	1,044,463	533,160
Rate of Return			PRRTR	7.31%	5.33%	-3.10%	14.06%	9.65%	10.03%
Class Rate in % of Total			PRCLRT		73.0	-42.5	192.4	132.1	137.2

PPLICA Adjusted 12 CP Cost-of-Service Study
Pennsylvania Power & Light
Cost Allocation Details - Future Test Year Ended 9/30/95
Summary

	LP-5	LPEP	ISA	GH	SL/AL	Standby
Operating Expenses						
Operating & Maintenance Exp.						
Production						
Fuel	75,889	1,973	7,159	7,616	1,475	154
Power Purchases	42,954	1,145	4,000	4,746	793	92
Other Production	46,918	1,324	4,233	6,317	757	112
Total Production	165,761	4,441	15,391	18,678	3,024	357
Transmission	1,512	46	131	252	20	4
Distribution	2,367	83	216	2,145	5,604	6
Other Operating & Maint. Expenses	26,673	775	2,347	4,748	1,840	68
Total Operating & Maintenance Exp.	196,313	5,345	18,085	25,824	10,488	435
Depreciation Expense						
Production	33,392	1,011	2,883	5,571	435	91
Transmission	1,122	26	75	187	15	3
Distribution	1,415	47	126	1,409	4,680	4
Other Depreciation Exp.	1,115	34	96	230	133	3
Total Depreciation Expenses	37,044	1,118	3,180	7,397	5,262	101
Amortization Expenses (Acct. 406)	0	0	0	0	0	0
Total Depreciation & Amortization	37,044	1,118	3,180	7,397	5,262	101
Miscellaneous Allowable Expenses	(4,293)	(130)	(371)	(711)	(56	(12)
Taxes						
- Other Capital Stock	3,287	99	280	706	488	9
- Other w/o Cap Stock	6,166	183	533	1,257	853	16
Deferred Income Taxes	(3,877)	(116)	(344)	(394)	616	(10)
Net Investment Tax Credit	(907)	(27)	(77)	(198)	(158)	(2)
Gross Receipts Tax	12,684	361	1,073	1,825	892	50
PA & Federal Income Taxes	28,266	857	1,869	2,990	(574)	250
Total Taxes	45,619	1,357	3,334	6,186	2,116	313
Total Operating Expenses	274,683	7,690	24,228	38,696	17,810	837
Return	39,590	1,209	2,575	5,889	3,717	348
Total Rate Base	530,195	15,831	45,286	115,122	84,418	1,436
Rate of Return	7.47%	7.64%	5.69%	5.12%	4.40%	24.26%
Class Rate in % of Total	102.2	104.5	77.8	70.0	60.3	332.0

Exhibit ___ (SJB-2)
Page 6 of 6

APPENDIX B

PENNSYLVANIA POWER & LIGHT
Allocation of Proposed Rate Increase
50% Reduction in Existing Subsidies under PPLICA's 12 Coincident Peak COSS

	Total Sales Revenue	Rate Base	Current Income	Current ROR %
Residential				
RS, RTD, RTS	906,886,000	2,349,085,000	117,103,000	4.99%
General Service				
GS−1	162,217,000	298,181,000	41,919,000	14.06%
GS−3	507,172,000	1,044,463,000	100,808,000	9.65%
LP−4	273,353,000	533,160,000	53,464,000	10.03%
LP−5	259,612,000	530,195,000	39,590,000	7.47%
LPEP	8,405,000	15,831,000	1,209,000	7.64%
ISA	20,449,000	45,286,000	2,575,000	5.69%
GH	43,628,000	115,122,000	5,889,000	5.12%
Street & Area Lighting	21,161,000	84,418,000	3,717,000	4.40%
Standby	1,148,000	1,436,000	348,000	24.23%
Rate Schedule	2,204,031,000	5,017,177,000	366,622,000	7.31%
Other Revenues	53,479,000			
Annualization Adjustment	25,615,000			
Total Retail Revenues	2,283,125,000	5,017,177,000	366,622,000	

PENNSYLVANIA POWER & LIGHT
Allocation of Proposed Rate Increase
50% Reduction in Existing Subsidies under PPLICA's 12 Coincident Peak COSS

	Current Equalized Rate of Return					Equalized Rate of Return @ $262 Million Increase					
	Percent Increase	Revenue Increase	Income Increase	ROR %	Sales Revenue	Percent Increase	Revenue Increase	Annualization & Other RevenueCredit	Income Increase	ROR %	Sales Revenue
Residential											
RS, RTD, RTS	10.96%	99,356,467	54,552,543	7.307%	1,006,242,467	24.31%	220,487,115	(1,369,000)	121,812,053	10.17%	1,127,373,115
General Service											
GS-1	-22.60%	(36,662,578)	(20,129,911)	7.307%	125,554,422	-13.34%	(21,646,091)	(533,000)	(11,592,328)	10.17%	140,570,909
GS-3	-8.79%	(44,595,543)	(24,485,575)	7.307%	462,576,457	1.79%	9,090,920	(780,000)	5,419,716	10.17%	516,262,920
LP-4	-9.66%	(26,416,488)	(14,504,205)	7.307%	246,936,512	0.29%	803,641	(583,000)	761,347	10.17%	274,156,641
LP-5	-0.59%	(1,542,399)	(846,868)	7.307%	258,069,601	9.83%	25,525,111	(581,000)	14,333,790	10.17%	285,137,111
LPEP	-1.13%	(95,027)	(52,176)	7.307%	8,309,973	8.69%	730,525	0	401,101	10.17%	9,135,525
ISA	6.54%	1,337,198	734,200	7.307%	21,786,198	18.09%	3,698,764	0	2,030,839	10.17%	24,147,764
GH	10.53%	4,595,777	2,523,352	7.307%	48,223,777	24.52%	10,699,138	100,000	5,819,550	10.17%	54,327,138
Street & Area Lighting	21.10%	4,465,291	2,451,707	7.307%	25,626,291	42.08%	8,904,505	37,000	4,868,782	10.17%	30,065,505
Standby	-38.56%	(442,697)	(243,067)	7.307%	705,303	-32.04%	(367,813)	0	(201,951)	10.17%	780,187
Rate Schedule		0	0	7.307%	2,204,031,000	11.70%	257,925,815	(3,709,000)	143,652,898	10.17%	2,461,956,815
Other Revenues		0	0		53,479,000		795,000		436,502		54,274,000
Annualization Adjustment		0	0		25,615,000		2,914,000		1,599,957		28,529,000
Total Retail Revenues		0	0		2,283,125,000		261,634,815		145,689,357	10.21%	2,544,759,815

PENNSYLVANIA POWER & LIGHT
Allocation of Proposed Rate Increase
50% Reduction in Existing Subsidies under PPLICA's 12 Coincident Peak COSS

	Current Sales Revenue	Revenue at Current Equal ROR	Current Subsidy	Revenue at Proposed Equal ROR	Proposed Subsidy	Proposed Sales Revenue	Proposed * Revenue Increase	Proposed * Percentage Increase
Residential					50%			
RS, RTD, RTS	906,886,000	1,006,242,467	(99,356,467)	1,127,373,115	(49,678,233)	1,077,694,882	170,808,882	18.83%
General Service								
GS−1	162,217,000	125,554,422	36,662,578	140,570,909	18,331,289	158,902,198	(3,314,802)	−2.04%
GS−3	507,172,000	462,576,457	44,595,543	516,262,920	22,297,771	538,560,691	31,388,691	6.19%
LP−4	273,353,000	246,936,512	26,416,488	274,156,641	13,208,244	287,364,885	14,011,885	5.13%
LP−5	259,612,000	258,069,601	1,542,399	285,137,111	771,200	285,908,311	26,296,311	10.13%
LPEP	8,405,000	8,309,973	95,027	9,135,525	47,514	9,183,038	778,038	9.26%
ISA	20,449,000	21,786,198	(1,337,198)	24,147,764	(668,599)	23,479,165	3,030,165	14.82%
GH	43,628,000	48,223,777	(4,595,777)	54,327,138	(2,297,888)	52,029,249	8,401,249	19.26%
Street & Area Lighting	21,161,000	25,626,291	(4,465,291)	30,065,505	(2,232,645)	27,832,860	6,671,860	31.53%
Standby	1,148,000	705,303	442,697	780,187	221,348	1,001,536	(146,464)	−12.76%
Rate Schedule	2,204,031,000	2,204,031,000	(0)	2,461,956,815	(0)	2,461,956,815	257,925,815	11.70%
Other Revenues	53,479,000					54,274,000	795,000	
Annualization Adjustment	25,615,000					28,529,000	2,914,000	
Total Retail Revenues	2,283,125,000					2,544,759,815	261,634,815	10.28%

* These increases are based on the Company's requested $262 million increase. If the Commission authorizes a lower increase, as recommended by PPLICA, these values should be adjusted to reflect the approved increase.

APPENDIX C

PENNSYLVANIA POWER & LIGHT COMPANY
SUMMARY OF CLASS REVENUE INCREASES
USING COST-OF-SERVICE CRITERIA RECOMMENDED BY PPLICA*

RATE SCHEDULE	PRESENT REVENUE (w/roll-ins)	PROPOSED REVENUE (w/o cap)	PROPOSED % INCREASE (w/o cap)	PROPOSED $ INCREASE (w/o cap)	INCREASE IN EXCESS OF 1.5 X SYSTEM (17.6%)	"CAPPED" $ INCREASE	"CAPPED" % INCREASE
RS	$886,748,156	$1,053,722,834	18.83%	$166,974,678	$11,350,376	$155,624,301	17.55%
RTS	$19,773,844	$23,497,259	18.83%	$3,723,415	$253,105	$3,470,310	17.55%
RTD	$363,891	$432,412	18.83%	$68,521	$4,658	$63,863	17.55%
GS-1	$161,735,899	$158,436,487	-2.04%	($3,299,412)	$0	$0	0.00%
GS-3	$506,985,301	$538,367,691	6.19%	$31,382,390	$0	$37,587,935	7.41%
LP-4:							
LP-4, L4C	$267,879,730	$279,582,944	4.37%	$11,703,214	$0	$15,016,205	5.61%
INTERRUPTIBLE	$18,728,254	$22,055,332	17.77%	$3,327,078	$40,269	$3,286,809	17.55%
ECO/IND DEV CR.	($13,254,820)	($14,273,227)	7.68%	($1,018,407)	$0	($1,018,407)	7.68%
LP-5:							
LP-5	$148,535,286	$157,538,352	6.06%	$9,003,066	$0	$10,822,489	7.29%
LP-6	$32,506,451	$33,729,757	3.76%	$1,223,306	$0	$1,626,705	5.00%
INTERRUPTIBLE	$91,661,728	$107,934,006	17.75%	$16,272,278	$185,644	$16,086,633	17.55%
ECO/IND DEV CR.	($13,090,615)	($13,292,954)	1.55%	($202,339)	$0	($202,339)	1.55%
LPEP	$8,404,855	$9,183,145	9.26%	$778,290	$0	$879,361	10.46%
ISA	$20,448,546	$23,479,021	14.82%	$3,030,475	$0	$3,268,424	15.98%
IS-1	$186,035	$197,551	6.19%	$11,516	$0	$13,793	7.41%
BL	$480,920	$471,109	-2.04%	($9,811)	$0	$0	0.00%
SA	$4,292,175	$5,645,498	31.53%	$1,353,323	$600,046	$753,277	17.55%
SM	$1,618,482	$2,128,789	31.53%	$510,307	$226,264	$284,044	17.55%
SHS	$14,778,848	$19,438,619	31.53%	$4,659,771	$2,066,083	$2,593,688	17.55%
SE	$346,823	$456,176	31.53%	$109,353	$48,486	$60,867	17.55%
TS(R)	$54,756	$72,021	31.53%	$17,265	$7,655	$9,610	17.55%
SI-1(R)	$69,788	$91,792	31.53%	$22,004	$9,756	$12,248	17.55%
GH-1(R)	$36,095,375	$43,047,344	19.26%	$6,951,969	$617,231	$6,334,738	17.55%
GH-2(R)	$7,533,184	$8,984,075	19.26%	$1,450,891	$128,817	$1,322,074	17.55%
STANDBY	$1,148,211	$1,001,699	-12.76%	($146,512)	$0	$0	0.00%
TOTAL PUC	$2,204,031,103	$2,461,927,731	11.70%	$257,896,628	$15,538,391	$257,896,628	11.70%
OTHER REV	$53,479,000	$54,274,118	1.49%	$795,118		$795,118	1.49%
ANN ADJ.	$25,615,499	$28,529,260	11.37%	$2,913,761		$2,913,761	11.37%
FERC	$483,916,000	$483,916,000	0.00%	$0		$0	0.00%
TOTAL OP REV	$2,767,041,602	$3,028,647,109	9.45%	$261,605,507		$261,605,507	9.45%

* Based on PP&L requested $262 million increase. If the Commission authorizes a lower increase, these values should be adjusted to reflect the approved increase.

Exhibit ___ (SJB-4)

APPENDIX D

PENNSYLVANIA POWER & LIGHT COMPANY
SUMMARY OF PROPOSED CLASS REVENUE INCREASES
ASSUMING A $20 MILLION AUTHORIZED REVENUE INCREASE

RATE SCHEDULE	PRESENT REVENUE (w/roll-ins)	PROPOSED REVENUE (w/o cap)	PROPOSED % INCREASE (w/o cap)	PROPOSED $ INCREASE (w/o cap)	INCREASE IN EXCESS OF 1.5 X SYSTEM (17.6%)	REVISED % INCREASE (@ $262 Million)	REVISED $ INCREASE (@ $262 Million)	REVISED $ INCREASE (@ $20 Million)	REVISED % INCREASE (@ $20 Million)
RS	$886,748,156	$1,053,722,834	18.83%	$166,974,678	$11,350,376	17.55%	$155,624,301	$12,138,646	1.37%
RTS	$19,773,844	$23,497,259	18.83%	$3,723,415	$253,105	17.55%	$3,470,310	$270,683	1.37%
RTD	$363,891	$432,412	18.83%	$68,521	$4,658	17.55%	$63,863	$4,981	1.37%
GS-1	$161,735,899	$158,436,487	-2.04%	($3,299,412)	$0	0.00%	$0	$0	0.00%
GS-3	$506,985,301	$538,367,691	6.19%	$31,382,390	$0	7.41%	$37,587,935	$2,931,847	0.58%
LP-4:									
LP-4, L4C	$267,879,730	$279,582,944	4.37%	$11,703,214	$0	5.61%	$15,016,205	$1,171,259	0.44%
INTERRUPTIBLE	$18,728,254	$22,055,332	17.77%	$3,327,078	$40,269	17.55%	$3,286,809	$256,370	1.37%
ECO/IND DEV CR.	($13,254,820)	($14,273,227)	7.68%	($1,018,407)	$0	7.68%	($1,018,407)	($1,018,407)	7.68%
LP-5:									
LP-5	$148,535,286	$157,538,352	6.06%	$9,003,066	$0	7.29%	$10,822,489	$844,151	0.57%
LP-6	$32,506,451	$33,729,757	3.76%	$1,223,306	$0	5.00%	$1,626,705	$126,882	0.39%
INTERRUPTIBLE	$91,661,728	$107,934,006	17.75%	$16,272,278	$165,644	17.55%	$16,066,633	$1,254,752	1.37%
ECO/IND DEV CR.	($13,090,615)	($13,292,954)	1.55%	($202,339)	$0	1.55%	($202,339)	($202,339)	1.55%
LPEP	$8,404,855	$9,183,145	9.26%	$778,290	$0	10.46%	$879,381	$68,590	0.82%
ISA	$20,448,546	$23,479,021	14.82%	$3,030,475	$0	15.98%	$3,268,424	$254,936	1.25%
IS-1	$186,035	$197,551	6.19%	$11,516	$0	7.41%	$13,793	$1,076	0.58%
BL	$480,920	$471,109	-2.04%	($9,811)	$0	0.00%	$0	$0	0.00%
SA	$4,292,175	$5,645,498	31.53%	$1,353,323	$600,046	17.55%	$753,277	$58,755	1.37%
SM	$1,618,482	$2,128,789	31.53%	$510,307	$226,264	17.55%	$284,044	$22,155	1.37%
SHS	$14,778,848	$19,438,619	31.53%	$4,659,771	$2,066,083	17.55%	$2,593,688	$202,307	1.37%
SE	$346,823	$456,176	31.53%	$109,353	$48,486	17.55%	$60,867	$4,748	1.37%
TS(R)	$54,756	$72,021	31.53%	$17,265	$7,655	17.55%	$9,610	$750	1.37%
SI-1(R)	$69,788	$91,792	31.53%	$22,004	$9,756	17.55%	$12,248	$955	1.37%
GN-1(R)	$36,095,375	$43,047,344	19.26%	$6,951,969	$617,231	17.55%	$6,334,738	$494,108	1.37%
GN-2(R)	$7,533,184	$8,984,075	19.26%	$1,450,891	$128,817	17.55%	$1,322,074	$103,121	1.37%
STANDBY	$1,148,211	$1,001,699	-12.76%	($146,512)	$0	0.00%	$0	$0	0.00%
TOTAL PUC	$2,204,031,103	$2,461,927,731	11.70%	$257,896,628	$15,538,391	11.70%	$257,896,628	$18,990,326	0.86%
OTHER REV	$53,479,000	$54,274,118	1.49%	$795,118		1.49%	$795,118	$795,118	1.49%
ANN ADJ.	$25,615,499	$28,529,260	11.37%	$2,913,761		11.37%	$2,913,761	$214,556	0.84%
FERC	$483,916,000	$483,916,000	0.00%	$0		0.00%	$0	$0	0.00%
TOTAL OP REV	$2,767,041,602	$3,028,647,109	9.45%	$261,605,507		9.45%	$261,605,507	$20,000,000	0.72%

Exhibit___ (SJB-5)

APPENDIX E

PENNSYLVANIA POWER & LIGHT COMPANY
PPLICA PROPOSED LP-5, LP-6, AND INTERRUPTIBLE RATES
REVENUE SUMMARY - ASSUMING A $262 MILLION INCREASE

PRESENT REVENUES

	Present Base	Roll-in Special Base Rate Adj. (-0.64%)	Roll-in St Tax Adj. Surcharge (-.49%)	Roll-in ECR $0.010836	Special Base Rate Adj. (-1.66%)	ECR ($0.000781)	Total Present Revenues
LP-5	$124,536,516	($797,034)	($596,194)	$28,118,816	($2,510,951)	($2,026,651)	$146,724,502
LP-5 : LP-6	$27,031,041	($172,999)	($129,406)	$6,392,037	($549,803)	($460,703)	$32,110,167
Interruptible	$69,478,880	($444,665)	($332,616)	$25,219,457	($1,559,090)	($1,817,681)	$90,544,286
Total (based on bill freq.)	$221,046,438	($1,414,697)	($1,058,216)	$59,730,311	($4,619,844)	($4,305,036)	$269,378,956
Actual Revenue	$223,703,000	($1,431,699)	($1,070,933)	$60,543,712	($4,676,952)	($4,363,662)	$272,703,466
Economic Devp credit	($12,333,000)		$60,432		($1,003)		($12,273,571)
Industrial Devp credit	($821,000)		$4,023		($67)		($817,044)
Total	$210,549,000	($1,431,699)	($1,006,479)	$60,543,712	($4,678,022)	($4,363,662)	$259,612,850

PROPOSED REVENUES

	Proposed Base	Special Base Rate Adj. (-1.66%)	ECR ($0.000781)	Total Proposed Revenues	Increase	% Increase
LP-5	$162,186,634	($2,692,298)	($2,026,651)	$157,467,684	$10,743,182	7.3%
LP-5 : LP-6	$34,763,890	($577,081)	($460,703)	$33,726,106	$1,615,938	5.0%
Interruptible	$110,117,234	($1,827,946)	($1,817,681)	$106,471,606	$15,927,321	17.6%
Total (based on bill freq.)	$307,067,757	($5,097,325)	($4,305,036)	$297,665,396	$28,286,441	10.5%
Actual Revenue	$310,768,208	($5,158,752)	($4,363,662)	$301,245,793	$28,542,328	10.5%
Economic Devp credit	($12,471,954)			($12,471,954)		
Industrial Devp credit	($821,000)			($821,000)		
Total	$297,475,254	($5,158,752)	($4,363,662)	$287,952,839	$28,339,989	10.9%

PENNSYLVANIA POWER & LIGHT COMPANY
PPLICA PROPOSED LP-5, LP-6, AND INTERRUPTIBLE RATES
PROOF OF REVENUE ANALYSIS – ASSUMING A $262 MILLION INCREASE

LP-5

Present Rate	UNITS	RATE	REVENUE
All Kw	4,953,919	$4.3900	$21,747,704
Kwh Blocks			
First 150/kw (max 1,200,000)	618,259,296	$0.0486	$30,047,402
Next 100/kw	489,809,450	$0.0443	$21,698,559
Next 150/kw	703,161,490	$0.0368	$25,876,343
Excess	783,714,030	$0.0321	$25,157,220
Subtotal	2,594,944,266		$102,779,524
TOD Metering	774	$12.0000	$9,288
Total			$124,536,516

Proposed	UNITS	RATE	REVENUE
All Kw	4,953,919	$5.8950	$29,203,486
Kwh Blocks			
First 400/kw	1,929,777,036	$0.0550	$106,176,817
Excess	665,167,230	$0.0403	$26,794,721
Subtotal	2,594,944,266		$132,971,538
TOD Metering	774	$15.0000	$11,610
Total			$162,186,634

LP-5 – Interruptible

Present Rate	UNITS	RATE	REVENUE
All Kw	485,656	$9.6000	$4,662,298
Kwh Blocks			
First 400/kw	194,262,400	$0.0321	$6,235,823
Excess	289,036,600	$0.0214	$6,185,383
Subtotal	483,299,000		$12,421,206
TOD Metering	168	$12.0000	$2,016
Total			$17,085,520

Proposed	UNITS	RATE	REVENUE
All Kw	485,656	$11.2883	$5,482,230
Kwh Blocks			
First 400/kw	194,262,400	$0.0541	$10,504,381
Excess	289,036,600	$0.0360	$10,419,414
Subtotal	483,299,000		$20,923,796
TOD Metering	168	$15.0000	$2,520
Total			$26,408,546

PENNSYLVANIA POWER & LIGHT COMPANY
PPLICA PROPOSED LP-5, LP-6, AND INTERRUPTIBLE RATES
PROOF OF REVENUE ANALYSIS - ASSUMING A $262 MILLION INCREASE

LP-5 : LP-6 Present Rate	UNITS	RATE	REVENUE
All Kw	1,057,999	$4.3900	$4,644,616
Kwh Blocks			
First 150/kw (max 1,200,000)	85,682,700	$0.0486	$4,164,179
Next 100/kw	105,799,900	$0.0443	$4,686,936
Next 150/kw	158,699,850	$0.0368	$5,840,154
Excess	239,706,550	$0.0321	$7,694,580
Subtotal	589,889,000		$22,385,850
TOD Metering	48	$12.0000	$576
Total			$27,031,041
Proposed			
All Kw (10,000 kw min)	1,067,331	$5.9592	$6,360,489
Kwh Blocks			
First 400/kw (min use)	426,932,400	$0.0546	$23,321,792
Next 200/kw	136,526,200	$0.0318	$4,339,164
Excess	28,709,000	$0.0258	$741,364
Subtotal	592,167,600		$28,402,321
TOD Metering	72	$15.0000	$1,080
Total			$34,763,890

LP-5: LP-6 - Interruptible Present Rate	UNITS	RATE	REVENUE
All Kw	931,427	$9.6000	$8,941,699
Kwh Blocks			
First 400/kw	372,570,800	$0.0321	$11,959,523
Excess	1,471,507,230	$0.0214	$31,490,255
Subtotal	1,844,078,030		$43,449,777
TOD Metering	157	$12.0000	$1,884
Total			$52,393,361
Proposed			
All Kw	931,427	$11.2883	$10,514,226
Kwh Blocks			
First 400/kw	372,570,800	$0.0541	$20,146,080
Excess	1,471,507,230	$0.0360	$53,046,028
Subtotal	1,844,078,030		$73,192,108
TOD Metering	157	$15.0000	$2,355
Total			$83,708,688

Exhibit ___ (SJB-6)
Page 3 of 3

APPENDIX F

TABLE I
INCOME SUMMARY
($000)

	Pro Forma *Present Rates*	Recommended *Adjustments*	Adjusted *Present Rates*	Revenue *Adjustments*	Total Allowable *Revenues*
Operating Revenues	2,402,255	21,790	2,424,045	**23,886**	2,447,931
Deductions:					
O&M Expenses	1,372,927	(72,825)	1,300,102	0	1,300,102
Depreciation	320,797	(47,075)	273,722	0	273,722
Reg'y Debits/ Credits	(29,208)	0	(29,208)	0	(29,208)
Gain	(466)	0	(466)	0	(466)
Taxes:					
State	54,478	1,111	55,589	1,219	56,808
Federal	130,552	13,457	144,009	2,491	146,500
Other	186,553	44,275	230,828	7,061	237,889
Total Deductions	**2,035,633**	**(61,057)**	**1,974,576**	**10,771**	**1,985,347**
Net Income Available For Return	366,622	82,847	449,469	13,115	462,584
Rate Base					**5,017,178**
Recommended Rate of Return*					**9.22%**

*** Cost of common equity @ 10.85%**

TABLE II
SUMMARY OF ADJUSTMENTS
($000)

Recommended Adjustment	Exhibit Reference	Rate Base Effect	Revenue Effect	Expense Effect	Depreciation Effect	Effect Taxes-Other	State Tax Effect	Federal Tax Effect
Fossil Dismantling	-	0	0	(43,041)	0	0	4,778	13,543
Shorter Depr.Lives	-	0	0	0	(16,687)	0	0	6,133
Levelization SSES depr.	-	0	0	0	(30,388)	0	3,540	10,033
ModifyDecom. accrual	-	0	0	(18,911)	0	0	2,078	5,890
VERP costs: gross to net &	-	0	0	(5,019)	0	0	552	1,563
5 to 10 yr. amortization	-	0	0	(4,057)	0	0	426	1,264
SFAS 106 Deferral	-	0	0	(1,797)	0	0	197	560
Computation Error	-	0	21,790	0	0	1,111	2,273	6,442
Cap. Struct.	-	0	0	0	0	0	(407)	(1,153)
TOTAL ADJUSTMENTS	-	**0**	**21,790**	**(72,825)**	**(47,075)**	**1,111**	**13,457**	**44,275**

CERTIFICATE OF SERVICE

I hereby certify that I have served two copies of the foregoing Main Brief on Behalf of the PP&L Industrial Customer Alliance on all known parties of record to this proceeding, in the manner indicated below, properly addressed as follows:

Service Via Hand-Delivery

OFFICE OF ADMINISTRATIVE LAW JUDGES
Hon. Robert A. Christianson
Administrative Law Judge
PA Public Utility Commission
G-08A North Office Building
P.O. Box 3265
Harrisburg, PA 17105-3265

OFFICE OF CONSUMER ADVOCATE
Tanya J. McCloskey, Esquire
Mary C. Kenney, Esquire
Assistant Consumer Advocates
Office of Consumer Advocate
1425 Strawberry Square
Harrisburg PA 17120

UNIVERSITY/COLLEGE COALITION
Daniel P. Delaney, Esquire
James P. Melia, Esquire
Kirkpatrick & Lockhart
204 North Third Street
Harrisburg, PA 17101-1507

CENTRAL EASTERN PENNSYLVANIA FUEL OIL DEALERS
Robert P. Haynes, Esquire
Mette, Evans & Woodside
3401 North Front Street
P.O. Box 5950
Harrisburg, PA 17110-0950

OFFICE OF TRIAL STAFF
Kenneth L. Mickens, Esquire
Johnnie E. Simms, Esquire
Office of Trial Staff
PA Public Utility Commission
P.O. Box 3265
Harrisburg, PA 17105-3265

OFFICE OF SMALL BUSINESS ADVOCATE
Karen Oill Moury, Esquire
Office of Small Business Advocate
Suite 1102, Commerce Building
300 North Second Street
Harrisburg, PA 17101

CROWN AMERICAN CORPORATION
Kenneth Zielonis, Esquire
Stevens & Lee
208 North Third Street
Suite 310
P.O. Box 12090
Harrisburg, PA 17108-2090

Service by Federal Express:

PENNSYLVANIA POWER & LIGHT COMPANY
Paul E. Russell, Esquire
Associate General Counsel
Pennsylvania Power & Light Co.
Two North Ninth Street
Allentown, PA 18101-1179

David B. MacGregor, Esquire
Thomas P. Gadsen, Esquire
Anthony C. DeCusatis, Esquire
Morgan, Lewis & Bockius
2000 One Logan Square
Philadelphia, PA 19103

BETHLEHEM STEEL CORPORATION
Joan O. Brandeis, Esquire
Schnader, Harrison, Segal & Lewis
1600 Market Street, Suite 3600
Philadelphia, PA 19103

MID-ATLANTIC ENERGY PROJECT (SIERRA CLUB)
Alan J. Barak, Esquire
Mid-Atlantic Energy Project
Weidner Energy Law Clinic
3700 Vartan Way
Harrisburg, PA 17110-9450

Service via First Class Mail:

OFFICE OF CONSUMER ADVOCATE
Mr. Thomas Catlin
Mr. Matthew I. Kahal
Exeter Associates, Inc.
12510 Prosperity Drive,
Suite 350
Silver Spring, MD 20904

Mr. Dale Bridenbaugh
MHB Technical Associates
1723 Hamilton Avenue-Suite K
San Jose, CA 95125

DEPARTMENT OF DEFENSE
David A. McCormick, General Attorney
Regulatory Law OFfice
Office of the Judge Advocate General
Department of the Army
DAJA-RL 3848
901 N. Stuart Street, Room 71
Arlington, VA 22203-1837

THE LANCASTER CHAMBER OF COMMERCE AND INDUSTRY
Christopher S. Underhill, Esq.
Hartman Underhill & Brubaker
221 East Chesnut Street
Lancaster, PA 17602

COMMISSION ON ECONOMIC OPPORTUNITY
Mr. Craig Kuennen
Commission on Economic Opportunity
211 S. Main Street
Wilkes-Barre, PA 18701-1596

ERIC JOSEPH EPSTEIN
Mr. Eric Joseph Epstein
2308 Brandywine Drive
Harrisburg, PA 17110

UNIVERSITY/COLLEGE COALITION
Cook, Eisdorfer & Associates
2258 Schuetz Road
Suite 205
St. Louis, MO 63146

CENTRAL EASTERN PENNSYLVANIA FUEL OIL DEALERS
Mr. Steven Andersen
Economic & Policy Analysis, Inc.
13300 Council Bluff Drive
Austin, TX 78727

<u>Service via First Class Mail</u>:

OFFICE OF SMALL BUSINESS ADVOCATE
Mr. Robert D. Knecht
Industrial Economics,
Incorporated
2067 Massachusetts Avenue
Cambridge, MA 02140

Derrick P. Williamson

Dated this 16th day of June, 1995, in Harrisburg, Pennsylvania.